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NATURAL RESOURCES DEFENSE COUNCIL

January 14, 2014

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Department of Conservation
801 K Street MS 24-02
Sacramento, CA 95814
ATTN: Well Stimulation Regulations

Email: DOGGRRegulations@conservation.ca.gov

Via Electronic and U.S. Mail

Re: Comments on the Proposed Draft Regulations for the Use of Well Stimulation in Oil and Gas Production in the State of California

Dear Dr. Mark Nechodom and Staff:

On behalf of the Natural Resources Defense Council (NRDC)—which has 1.4 million members and activists, 250,000 of whom are Californians—we write to submit technical comments on the proposed draft regulations for the use of well stimulation in oil and gas production in the state of California.

Respectfully submitted,

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2 Moratorium on Well Stimulation

There is an urgent need for a moratorium on hydraulic fracturing, acidizing, and other forms of well stimulation in California. The controversial oil and gas extraction method known as hydraulic fracturing ("fracking") has ignited concerns nationwide about the serious risks it poses to public health and our environment. Here in California, a largely unfettered oil industry is poised to exploit the oil-rich Monterey Shale formation, putting communities at risk of surface and groundwater contamination, fresh water depletion, air pollution, greenhouse gas emissions, induced seismicity, land degradation, wildlife habitat fragmentation, and a host of other harmful consequences that accompany a highly industrial process that injects, at high pressures, toxic chemicals and hundreds of thousands to millions of gallons of water into the earth.

Despite these risks, to date hydraulic fracturing and other risky well stimulation processes, such as acidizing, enjoy dangerous exemptions from critical provisions of our landmark federal environmental laws and have proceeded woefully under-regulated by state law here in California.

The draft well stimulation regulations include a number of improvements over existing state oil and gas regulation and the previously proposed draft regulations; however, they fall short of providing adequate and enforceable safeguards for the risks of well stimulation treatments and the potential increase in drilling and associated activities. For these reasons we urge the Department of Conservation (Department) and its Division of Oil, Gas & Geothermal Resources (Division) to adhere to its mandate under Public Resources Code Section 3106, subsection (a) "to prevent, as far as possible, damage to life, health, property. . . natural resources" and "damage to underground and surface waters" and to, for that reason, impose an immediate moratorium on hydraulic fracturing, acidizing, and other forms of well stimulation in California.

New York's Governor issued an executive order halting hydraulic fracturing to give state regulators time to fully evaluate the risks to public health and the environment of these controversial processes and in order to determine how to best guard the state's drinking water and its communities against them. We urge the Department and the Division to proceed along a similar path and to implement an immediate moratorium on hydraulic fracturing, acidizing, and well stimulation as the state undergoes its scientific study of the impacts of hydraulic fracturing and other well stimulation treatments. Quite simply, it does not make sense to attempt to draft regulations governing an industry and process that is under study and still poorly overseen. Putting the cart before the horse in this way will mean that the regulations won't have the benefit (or be able to incorporate) what is learned in the statewide study of hydraulic fracturing or what is disclosed and learned as part of the California Environmental Quality Act (CEQA) environmental review process. This will unnecessarily increase the risks to human health and the environment.

The statewide study is charged with, among other things, investigating areas with existing and potential oil and gas reserves where well stimulation treatments are likely to spur exploration; evaluating additive and water transportation to and from the well site; studying the mixing and handling of well stimulation treatment fluids; investigating the use and potential for nontoxic additives and the use or reuse of treated or produced water in well stimulation treatment fluids; evaluating the disposal of flowback fluids; understanding the related atmospheric emissions, including greenhouse gases; investigating and reporting on impacts on wildlife; considering potential for seismicity; and undergoing a hazard assessment and risk analysis addressing occupational and environmental exposures to well stimulation treatments, including hydraulic fracturing treatments, hydraulic fracturing treatment-related processes, acid well stimulation treatments, acid well stimulation treatment-related processes, and the corresponding impacts on public health and safety. Each of these findings should inform the regulatory framework governing the drilling, operation, maintenance, and abandonment of well stimulation projects.

A moratorium does not just make sense; it is what the public wants. A majority of Californians agree that a moratorium on hydraulic fracturing is needed now. A poll by the University of Southern California and the Los Angeles Times showed that 58 percent of California voters want a moratorium on hydraulic fracturing, at least until an independent commission has studied hydraulic fracturing's environmental impacts. The Public Policy Institute of California's statewide study from September, 2013, found that 53 percent of Californians oppose increased use of hydraulic fracturing. These numbers reflect the same strong support we heard at the recent hearings. Across the state, at hearings on the proposed regulations and the statewide environmental impact report (EIR) required by Senate Bill 4 (SB 4), in geographically and culturally diverse cities including Oakland, Sacramento, Long Beach, Salinas, Bakersfield, Ventura, and Santa Maria, thousands of citizens spoke out in passionate and undeniable support of a ban or moratorium on hydraulic fracturing in California.

California has been at the forefront of environmental protection in many areas, but on hydraulic fracturing the state is still behind. The combination of advanced drilling and well stimulation techniques has made it possible to produce oil and gas from unconventional formations that were previously inaccessible. Policies that open up California to expanded fossil fuel investments – in contrast to clean energy – take us in the wrong direction on climate change by locking us into decades of carbon-intensive resources.

Until there is a better understanding of the risks of hydraulic fracturing, until we know the climate impacts from development of the Monterey Shale, and while the state studies the risks and how to protect public health and the environment against them, continued hydraulic fracturing leaves the health of Californians and our precious natural resources unprotected. For these reasons, we ask you to impose an immediate moratorium on hydraulic fracturing, acidizing, and other forms of well stimulation.

3 California Environmental Quality Act (CEQA) Review

Hydraulic fracturing, acidizing, and other forms of well stimulation in California must be subject to statewide as well as site-specific review under CEQA. One of the key provisions of the draft proposed regulations is the requirement that oil and gas companies obtain a permit from the Division before engaging in hydraulic fracturing, acid matrix stimulation, or other well stimulation of new or existing wells. Since these permits are discretionary, they are subject to CEQA just like any other big, potentially polluting project. The regulations must make clear that full site-specific CEQA review at the project level is required for each individual well—new or old—subject to well stimulation and that this includes underground injection wells where stimulation is employed.

CEQA makes environmental protection a mandatory part of every California state and local agency's decision making process. The statewide EIR required by SB 4 is an opportunity to consider cumulative impacts of increased hydraulic fracturing, acidizing, and well stimulation in California; viable statewide alternatives; and shared possible mitigation measures. The statewide EIR, however, cannot serve as complete and final environmental review under CEQA for all well stimulation projects going forward in California. Well-by-well and site-specific CEQA analysis is required because each location and each and every oil well in California has its own set of highly particular concerns and environmental considerations including: local water supply and hydrology, geology, faults and seismology, community and environmental justice concerns, and critical habitat and threatened or endangered species impacts. In order to ensure the full disclosure of a particular project's environmental impacts and to best adopt feasible measures to mitigate those local impacts, full site-specific CEQA review at the well level is required in addition to the statewide EIR.

We understand that Kern County is currently conducting its own countywide EIR. Kern County is the current epicenter of hydraulic fracturing, acidizing, and other well stimulation here in California. As the state conducts its EIR, the geographic scope of its environmental review must be statewide: it must not exclude analysis of Kern County. This is because the activities in Kern County necessarily affect statewide resources such as water and air, are a substantial part of any cumulative analysis, impact the climate change analysis, and have impacts on wildlife and human health throughout the state. Exclusion of Kern County conflicts with case law and the spirit of CEQA.

Finally, these regulations themselves have potentially significant environmental impacts and require CEQA review. These regulations are not categorically exempt from CEQA, and they should be subject to full consideration and public disclosure of their impacts as required by law.

4 Offshore Well Stimulation

The proposed draft rules should make express their applicability to and take into account regulatory requirements specific to hydraulic fracturing, acidizing, and other well stimulation in the offshore environment. The proposed draft regulations are purportedly applicable to California coastal waters. Yet, there is no mention in the draft regulations of hydraulic fracturing, acidizing, or well stimulation in the offshore environment. The proposed draft rules must be revised to expressly reflect the fact that they are applicable to the offshore environment, and they must take into account any necessary considerations particular to conducting well stimulation projects in the marine environment.

The state's current regulatory regime distinguishes between terrestrial and offshore oil and gas drilling and production.[i] This seems to reflect an understanding that the offshore environment has its own unique set of challenges and environmental considerations. The draft proposed regulations must also take into account the distinct challenges of the offshore environment. For example, in the offshore context, flowback and produced water are currently either discharged directly into the ocean or transported for onshore underground injection. When disposed of at sea, well stimulation chemicals and naturally occurring contaminants enter the fragile marine ecosystem. The coastal waters off California are a productive foraging region for whales and sea turtles and support a myriad of wildlife. We would ask that any well stimulation projects in the marine environment take special consideration of the impacts to wildlife and sensitive habitat, including important habitat for threatened and endangered species. In particular, we would ask that direct discharge into the ocean of hydraulic fracturing fluid, flowback fluid, drilling muds, produced water, or other well-stimulation related wastewaters be forbidden—just as open sump pits are outlawed in the terrestrial context.

The draft proposed regulations should also take into consideration, among other distinctions, increased vessel traffic and ship-strike mortality of whales, the potential for induced seismicity, air toxic emissions, and well casing specifications when regulating well stimulation in the offshore environment.

Because hydraulic fracturing is an inherently dangerous practice that has not yet been the subject of a comprehensive statewide study or environmental review, and the marine environment is a particularly fragile ecosystem, we would also ask that you impose an immediate moratorium on hydraulic fracturing in the offshore environment until the risks are fully studied and safeguards are put in place to guard against them.

5 Comments on the Proposed Regulations

The proposed draft rules include some positive advancements in public disclosure and notice, but they also suffer in their current draft form from definitions that are dangerously vague, arbitrary thresholds, impermissible exclusions, and other problems that risk impeding their efficacy. We offer our specific comments, concerns and suggestions below.

Unless otherwise noted, the conventions observed in this letter are that NRDC comments are in regular font, the text of proposed rules are inset regular font, suggested deletions are in ~~strikethrough~~, suggested additions are <u>underlined</u>.

5.1 1751. Single-Project Authorization.

The Division's Initial Statement of Reasons (ISOR)[ii] states that the purpose of Section 1751 is to fulfill the requirements of Public Resources Code section 3160, subdivision (d)(2), which states, "At the supervisor's discretion, and if applied for concurrently, the well stimulation treatment permit described in this section may be combined with the well drilling and related operation notice of intent required pursuant to Section 3203 into a single combined authorization." The Division's proposed rules at Section 1751 would allow multiple stimulation and drilling permits to be combined into a single project authorization. This proposed rule seeks to expand the authority granted by subdivision (d)(2), which allows one well stimulation treatment permit to be combined with one well drilling permit. As such, we propose the following revisions:

1751. ~~Single-Project~~ Combined Authorization.

(a) For the purposes of this section, "~~single-project~~ combined authorization" shall mean a single Division approval for ~~multiple~~ a single application~~s~~ for a permit~~s~~ to perform a well stimulation treatment~~s~~ and/or a notice~~s~~ of intent to drill or rework a well~~s~~.

(b) A request for a ~~single-project~~ combined authorization shall include:

(1) Identification of each of the applications and notices that are part of the request;

(2) The applications and notices that comprise the request for a ~~single-project~~ combined authorization.

(c) The Division will specify what operations are approved by a ~~single-project~~ combined authorization and the conditions under which the operations are approved.

(d) Operations approved by a ~~single-project~~ combined authorization that have not commenced within one year shall not be commenced without first obtaining a new approval for those operations from the Division.

While we recognize that Governor Brown's signing statement directed the Division to allow permits to be grouped together, the Division did not include this as one of the reasons for creating Section 1751 in the ISOR. To the contrary, the Division stated in its SB4 Implementation Plan [iii] that it would not develop the regulation to implement the group permitting procedures outlined in the Governor's signing statement until January 2014.

In order to properly assess and mitigate potential environmental and human health impacts, a unique permit should be applied for, reviewed, and approved for each well on which stimulation operations will be performed. The ability to group multiple permits for the purpose of a single-project authorization may be acceptable, but the function of such a process should be to encourage and facilitate a comprehensive and cumulative analysis of potential environmental impacts and to develop strategies to mitigate these impacts. Grouping permits should not be used to relieve the operator of regulatory obligations or in any way limit the completeness or uniqueness of a permit application. Similarly, grouping permits should not reduce the amount or thoroughness of review of each permit by Division staff.

The state of Colorado has developed a voluntary program for operators to develop a Comprehensive Drilling Plan, the goal of which is "to identify foreseeable oil and gas activities in a defined geographic area, facilitate discussions about potential impacts, and identify measures to minimize adverse impacts to public health, safety, welfare, and the environment, including wildlife resources, from such activities." We encourage the Division to review the details of this program and incorporate these concepts into any program for single-project authorization.

5.2 1761. Well Stimulation and Underground Injection Projects.

5.2.1 1761(a)(1) Definition of "Well Stimulation Treatment"

The term "well stimulation treatment" is too narrowly defined in the draft regulations and should be amended in the final regulations. In particular, the definition should not limit the regulations to treatments that penetrate a formation more than 36 inches from the well-bore. This threshold is arbitrary, has no basis in the implementing legislation—the newly added sections of Article 3, Chapter 1 of Division 3 of the Public Resources Code never mention any 36 inch exclusion—and could leave potentially dangerous processes unregulated or under-regulated. We also object to the proposal to exempt underground injection projects from well stimulation regulations. We propose the following revised definition:

(a) The following definitions are applicable to this chapter:

(1) "Well stimulation treatment" means a treatment of a well designed to enhance oil and gas production or recovery by ~~increasing~~ modifying the permeability of the formation. ~~Well stimulation is a short term and non-continual process for the purposes of opening and stimulating channels for the flow of hydrocarbons.~~ Examples of well stimulation treatments include hydraulic fracturing, acid fracturing, and acid matrix stimulation. Well stimulation treatment does not include ~~routine well cleanout work; routine well maintenance; routine treatment for the purpose of removal of formation damage due to drilling; bottom hole pressure surveys;~~ routine well cleanout or maintenance activities that do not affect the integrity of the well or the formation~~; the removal of scale or precipitate from the perforations, casing, or tubing; or a treatment that does not penetrate into the formation more than 36 inches from the wellbore~~.

(2) Well stimulation treatments do not include enhanced oil recovery techniques. ~~"Underground injection project" or "subsurface injection or disposal project" means sustained or continual injection into one or more wells over an extended period in order to add fluid to a zone for the purpose of enhanced oil recovery, disposal, or storage~~. Examples of ~~underground injection projects~~ enhanced oil recovery techniques include waterflood injection, steamflood injection, cyclic steam injection, miscible gas injection, chemical flooding, and microbial flooding ~~injection disposal, and gas storage projects~~.

~~(b) Well stimulation treatments and underground injection projects are two distinct kinds of oil and gas production processes. Unless a regulation expressly addresses both well stimulation and underground injection projects,~~

~~(1) Regulations regarding well stimulation treatments do not apply to underground injection projects; and~~

~~(2) Regulations regarding underground injection projects do not apply to well stimulation.~~

The definition should be inclusive of all stimulation techniques.

The purpose of stimulation is to restore or enhance the delivery of hydrocarbons to the wellbore. Reservoir stimulation accomplishes this primarily by restoring, improving, increasing or otherwise modifying the permeability of the target formation. As such, we request that the term "increasing" be replaced by the word "modifying" in the definition, because not all stimulation techniques will increase the permeability of the formation. Although the word "increasing" was used in the well stimulation treatment definition in SB4, we believe this revision is consistent with the intent of the law to regulate all well stimulation techniques.

Currently, stimulation practices fall into two main categories: matrix stimulation and fracture stimulation. For matrix stimulation treatments, fluids are injected below the fracture pressure of the target formation; for fracture stimulation treatments, fluids are injected above the fracture pressure of the target formation. Acid matrix stimulation or "acidizing" is the most common form of matrix stimulation; hydraulic fracturing is the most common form of fracture stimulation. However, researchers are also experimenting with novel forms of stimulation, including cryogenic fracturing [iv] and controlled underground explosions. [v] The definition of "well stimulation" must be broad enough to encompass current as well as potential future stimulation techniques. The definition proposed by the Division falls short of this goal.

Vague terms should be removed.

The term "well stimulation treatment" is too vaguely defined. The definition should not include the modifier that it refers to a "short term and non-continual process." Neither "short term" nor "continual" are defined, and they are vague terms open to liberal and varied interpretations. The term "underground injection project" or "subsurface injection or disposal process project," which is limited to "sustained or continual injection . . . over an extended period" suffers from the same ambiguity.

As an initial matter, this distinction between short term and non-continual and continual injection has no basis in SB 4 or the newly added sections of Article 3, Chapter 1 of Division 3 of the Public Resources Code.

More importantly, the vagueness invites abuse. The problem with such a distinction is demonstrated by the very express examples offered in the draft regulations. For example, cyclic steam injection is listed as an "underground injection project"; however, cyclic steam injection (aka "Huff and Puff") is—as its own name implies—a process that starts and stops. It is non-continual. The initial injection phase can last days to weeks. It is unclear from the definition as currently drafted whether a process that lasts days is "short term".

Without a concrete definition of short term and continual, these ambiguities invite mischief and, when a dispute arises, will leave the courts with little guidance to define or distinguish between "short term" or "non-continual" v. "continual." At this time, it may be possible to identify most of the common unconventional methods of extraction and to sort them by name into the two categories presented here. However, oil and gas in California is a rapidly evolving industry and as the examples in the statue demonstrate, there are many methods of extraction and they are often hybrids of one another. If "non-continual" and "continual" are left in the final regulations without definite temporal limits, a company engaged in a new unconventional extraction process will too easily be able to regulation shop, deciding whether to be bound by the regulations covering "well stimulation" or, if it is more desirable, by those applicable to "underground injection process." Such uncertainty is not in the interest of protecting public safety and health, judicial economy, regulatory certainty; nor was it the intention of Senate Bill 4.

The penetration distance threshold should be removed.
We object to the use of arbitrary thresholds to create distinct classes of well stimulation. The proposed threshold creates different regulatory regimes not just for the actual act of well stimulation, but also for many other steps in the extraction process, for example, public notice, well construction, chemical disclosure, and waste water handling. In practice, this means that oil and gas extraction performed below the threshold is not subject to the more stringent rules that apply to extraction above the threshold. As such, the proposed threshold creates a system in which regulations to prevent environmental and human health impacts are not consistently applied across all oil and gas operations. Moreover, California law does not provide discretion to the Division to exempt a subset of well stimulation from permitting and other legal requirements enacted in SB 4 and applicable, by law, to all well stimulation. *See, e.g.*, Cal. Pub. Res. Code § 3160 (d)(1) (requiring that "prior to performing a well stimulation treatment on a well, the operator shall apply for a permit").

The Division has presented no legal or scientific basis for excluding treatments that do not penetrate into the formation more than 36 inches from the wellbore. If the goal is to exclude routine maintenance or clean-up activities then this addition is redundant, as those activities are already explicitly excluded from the definition. The penetration distance threshold is problematic for several reasons:

- The Division provides no information as to how the penetration distance should be determined or verified. It is unclear if or how the Division will assess whether a proposed treatment meets the threshold. The proposed rules appear to provide complete discretion to the operator to decide whether or not a proposed stimulation treatment will meet the penetration distance threshold, and consequently whether or not to apply for a permit. Unless operators are required to submit a permit application for all proposed stimulation treatments, the Division will not have the information to make this determination independently. The Division has also failed to provide any requirements for how the anticipated penetration distance should be calculated. There is also no requirement for the penetration distance to be verified after stimulation.
- The proposed penetration distance threshold is arbitrary. Moreover, the concept of using a penetration distance threshold is not based in science. The Division has failed to provide any scientific information to justify the selection of 36 inches. It does not appear to be based on any actual data regarding the penetration distance of stimulation treatments or an analysis of risk. Furthermore, many of the risks that the legislature sought to address by requiring the Division to regulate well stimulation are not proportional to the penetration distance of a stimulation treatment, for example the use and handling of potentially hazardous chemicals and waste, and well integrity. The penetration distance concept also appears to be based on a false assumption that the treatment will penetrate radially into the formation. In reality, variations in the geologic properties of the target formation will result in variable penetration. As such, it is unclear whether the proposed 36 inch threshold should be considered an average, maximum, or

other measure. The penetration distance threshold concept does not have scientific or technical merit and the Division must abandon this provision. If finalized, this rule would set a dangerous precedent.

5.2.2 1761(a)(2) Definition of "Underground injection project" or "subsurface injection or disposal project"

As stated above, this definition suffers from the use of the vague phrase "sustained or continual injection . . . over an extended period." This definition should be deleted from the rules altogether.

5.2.3 1761(b) Well stimulation vs. underground injection

Excluding underground injection projects from the regulations full stop is problematic because many injection projects also utilize well stimulation. If underground injection wells are stimulated, they should be subject to these rules. Instead of exempting underground injection projects from regulations regarding well stimulation, we suggest that the regulations state that the forms of enhanced oil recovery (i.e. EOR; we include both secondary and tertiary recovery techniques in this term) contained in SB 4 and the newly added sections of Article 3, Chapter 1 of Division 3 of the Public Resources Code are not forms of stimulation and vice versa.

We believe, however, that the well stimulation treatment definition will already exclude enhanced oil recovery techniques because of the qualifier that well stimulation techniques must modify the permeability of the formation. Most enhanced oil recovery techniques are designed to modify the properties of the hydrocarbons or use specialized fluids to contact more of the reservoir rather than modifying the permeability of the rocks.[1]

5.3 1780. Purpose, Scope, and Applicability

The purpose, scope, and applicability of Article 4 (Well Stimulation Treatments) are too narrowly defined in the draft regulations and should be amended in the final regulations. In particular, the definition should not limit the regulations to acid matrix stimulations that utilize more than 7 percent concentration of acid. This threshold is arbitrary and could leave potentially dangerous processes unregulated or under-regulated.

In addition, this concentration threshold is in contravention of the plain text of Senate Bill 4. Senate Bill 4 mandates that the Division establish a threshold *volume* for acid, not a threshold concentration. Section 3160, subsection (b)(1)(C)(i) states that "the rules and regulations *shall* establish threshold values for acid *volume* applied per treated foot of any individual stage of the well or for total acid *volume* of the treatment, or both . . . ." [emphasis added].

In sum, section 1780 should be amended as follows:

(a) The purpose of this article is to set forth regulations governing well stimulation treatments, as defined in Section 1761, subdivision (a)(1).~~, except that t~~The requirements of this article ~~do not~~ apply to acid matrix stimulation treatments that use an acid volume

[1] Some EOR techniques may modify the reservoir rocks by changing wettability or by plugging off certain parts of the reservoir but typically do not modify permeability.

of more than 0 gallons per treated foot, or total acid volume of the treatment of more than 0 gallons ~~concentration of 7% or less~~. ~~Nor is a~~An operator is required to obtain a permit under Public Resources Code section 3160, subdivision (d), prior to performing an acid matrix stimulation treatment that uses an acid volume of more than 0 gallons per treated foot, or total acid volume of the treatment of more than 0 gallons ~~concentration of 7% or less~~.

~~(b) Well stimulation treatments are not subsurface injection or disposal projects and are not subject to Section 1724.6 through 1724.10. This article does not apply to underground injection projects.~~

(c) For purposes of this article, a well stimulation treatment commences when well stimulation equipment or materials are brought to the wells site ~~fluid is pumped into the well~~, and ends when ~~well stimulation treatment equipment is disconnected from the well~~ either the well is shut in or when the well continuously flows to the flow line or to a storage vessel for collection, whichever occurs first.

As stated in section 1.2.1 above, we object to the use of arbitrary thresholds to create distinct classes of well stimulation because they create different standards of environmental protection that have no basis in science or risk. SB4 directs the Division to set the volumetric threshold "based upon a quantitative assessment of the risks posed by acid matrix stimulation treatments that exceed the specified threshold value or values in order to prevent, as far as possible, damage to life, health, property, and natural resources pursuant to Section 3106." The Division has failed to provide such an assessment to support the proposed concentration threshold. Furthermore, given that the Division does not currently collect data on acid volumes and concentrations in a systematic way, we believe that the data to perform such an analysis do not exist at this time. In the ISOR, the Division claims that the concentration threshold is based on "the Division's evaluation of the available information…" but then states one paragraph later that "the Division has limited data about the specifics of acid matrix stimulation in the state." As the Division recognizes in the ISOR, Public Resources Code section 3160, subdivision (b)(1)(C) directs the Division to review and, if needed, revise the threshold on or before January 1, 2020. As such, the Division should set the threshold volume at zero until at least that time, when, as stated in the ISOR, "the Division will have the benefit of a great deal of new information about well stimulation treatment in the state." Given the current lack of data, any volume of acid should be subject to the proposed rules.

As stated above in section 1.2.3 above, we object to the proposal to exempt underground injection projects from well stimulation regulations. Underground injection wells often use well stimulation treatments including acid stimulation, in which case they should be subject to these rules.

5.4 1781. Definitions.

We propose the following revisions to the proposed definitions:

(a) "~~Acid m~~Matrix stimulation treatment" means a~~n acid~~ well stimulation treatment conducted at pressures lower than the fracture pressure of ~~applied pressure necessary to~~

~~fracture~~ the target underground geologic formation, in order to cause, restore, or enhance the production of hydrocarbons from a well. Matrix stimulation treatments include, but are not limited to, acid matrix stimulation treatments.

~~(c) "Acid stimulation treatment fluid" means one or more base fluids mixed with physical and chemical additives for the purpose of performing an acid well stimulation treatment.~~

(h) "~~Hydraulic fracturing~~Fracture stimulation treatment" means a well stimulation treatment conducted at pressures above the fracture pressure of the ~~that, in whole or in part, includes the pressurized injection of~~ ~~hydraulic fracturing fluid into an~~ target underground geologic formation in order to ~~fracture the formation, thereby~~ cause~~ing~~, restore, or enhance~~ing~~, for the purposes of this division, the production of oil or gas from a well.

~~(i) "Hydraulic fracturing fluid" means one or more base fluids mixed with physical and chemical additives for the purpose of hydraulic fracturing.~~

5.5 1782. General Well Stimulation Treatment Requirements.

We support the intent of this section and suggest the following revisions and additions:

(1) The casing design includes safety measures that ensure well control during drilling and completion and safe operations during the life of the well and ~~C~~casing is sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times;

(3) All potentially productive zones, zones capable of over-pressurizing the surface casing annulus, or corrosive zones be isolated and sealed off to the extent that such isolation is necessary to prevent vertical migration of fluids or gases behind the casing or prevent exterior corrosion of the casing;

(6) The well stimulation treatment fluids used are of known quantity and description for reporting and disclosure as required pursuant to this Article; and

(7) The well stimulation treatment fluid ~~is not of a concentration level that~~ will not damage the well casing, tubing, cement, or other well equipment, or ~~would~~ otherwise cause degradation of the well's mechanical integrity during the treatment process. All well construction materials are compatible with fluids with which they may come into contact and are resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

5.6 1783. Application for Permit to Perform Well Stimulation Treatment.

We support the proposed requirements of this section.

5.7 1783.1. Contents of Application for Permit to Perform Well Stimulation Treatment.

All well stimulation permits must be made publicly available and posted to the Division's website. To assure the public that permits will be made available with adequate time for public review, the division should amend these regulations to state that all permits must be posted on its site for at least 30 days before issuance. We also suggest the following revisions and additions to the proposed contents of the well stimulation permit:

(12) For directionally drilled wells, the proposed coordinates of the surface and bottom hole locations ~~(from surface location)~~, the true vertical depth at total depth, and the wellbore path;

(13) Estimated true vertical and measured depth of the well;

(15) The planned location of the well stimulation treatment on the well bore including the measured and true vertical depth of all perforations or the open-hole interval, the estimated length, height, and ~~direction~~ orientation of the induced fractures or other planned modification, if any, and the location of existing wells, including plugged and abandoned wells, that may be impacted by these fractures and modifications;

(16) Depth ~~of~~ to the top and base of protected water, reported as both measure depth and true vertical depth;

(17) ~~Anticipated volume, rate, and pressures of fluid to be injected;~~

(18) Identification of all wells that have previously been ~~hydraulically fractured~~ stimulated in the same production horizon within the area of twice the largest dimension of the anticipated ~~fracture radius~~ well stimulation treatment radius as determined under Section 1784(a)(2);

(21) The well stimulation treatment radius analysis required under Section 1784(a)(2), including identification of all water within the area of twice the largest dimension of the well stimulation treatment radius analysis including maps and stratigraphic cross sections indicating the general vertical and lateral limits of all water, their positions relative to the production/stimulated zone(s), and the direction of water movement, where known; and the names and API numbers of all wells within the area of twice the largest dimension of the well stimulation treatment radius analysis;

(22) The well stimulation treatment design required under Section 1784(a)(3) including:~~;~~

(i) The estimated type and volume of base fluid used in the well stimulation treatment, expressed in gallons or other units approved by the Division and, if water, each water source should be reported separately and should include information on source type (oilfield produced or wastewater, municipal or industrial wastewater, surface water, groundwater, municipal water, or specify other source), source location, volume, supplier, whether the water has been treated or recycled, and, for groundwater, TDS content.

(ii) The estimated total volume of fluid and, if applicable, proppant to be used;

(iii) The anticipated surface treating pressure range;

(iv) The maximum anticipated pumping pressure;

(v) The operating procedure; and

(vi) The estimated or calculated fracture gradient of the producing and confining zone(s).

(23) A water management plan that includes:

(i) an estimate of the amount of water to be used in the treatment,

(ii) an estimate of water to be recycled following the well stimulation treatment,

(iii) the anticipated source of the water to be used in the treatment,

(iv) the anticipated of timing of withdrawal of any surface or ground water,

(v) Anticipated transport distances and methods for base fluid and waste water (e.g. pipeline, truck) and methods to minimize related impacts including but not limited to land disturbance, traffic, vehicle accidents, and air pollution.

(vi) Anticipated on-site storage methods for base fluid and waste water;

(vii) A description of methods the operator will use to maximize the use of non-potable water sources including reuse and recycling of wastewater;

(viii) An evaluation of potential adverse impacts to aquatic species and habitat, wetlands, and aquifers, including the potential for the introduction of invasive species, and methods to minimize those impacts; and

(ix) ~~and~~ the anticipated disposal method that will be used for the recovered water in the flowback fluid from the treatment that is not produced water that would be reported pursuant to Section 3227;

(26) A complete list of the names, Chemical Abstract Service numbers, volumes, and estimated concentrations, in percent by mass, of each and every chemical constituent of the well stimulation fluids anticipated to be used in the treatment. If a Chemical Abstract Service number does not exist for a chemical constituent, another unique identifier may be used, if available. A claim of trade secret protection for the information required under this section shall be handled in the manner specified under Public Resources Code section 3160, subdivision (j).

(27) The geologic review required under Section 1784(a)(2)(iii) and data demonstrating the presence of a suitable confining zone [see section 1.10.2.3 of these comments], including:

i. Maps and cross-sections of the well stimulation treatment radius analysis required under Section 1784(a)(2)

ii. Data on the depth (measured and true vertical), areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions

iii. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)

iv. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)

v. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area

vi. Hydrologic flow and transport data and modeling

(28) A map showing the well for which a permit is sought and line showing the surface projection of twice the largest dimension of the well stimulation treatment radius analysis. Within this line, the map must show all penetrations (e.g. production wells, injection wells, plugged wells, mines, etc.) State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected.

(29) An as-built well diagram and actual details of the casing and cementing program should be submitted prior to stimulation operations, including:

(i) Hole size

(ii) Casing size, weight, grade, collapse and burst values, connection type, and setting depth

(iii) Casing safety design factors for tension, collapse, and burst and assumptions made to arrive at those values
(iv) Type and amount of cement used and top of cement for each casing string
(v) If staged cementing was used:
a. The setting depth of the stage tool(s) and amount and type of cement, including additives, used in each stage
b. Yield of each cement slurry and top of cement for each cemented string or stage
(vi) Any problems encountered during well construction and a description of any remedial actions taken
(30) The results of any casing pressure tests, formation integrity tests, and mechanical integrity tests, including the pressure tests required under Section 1784.1(a)(1) & (2).

5.8 1783.2. Copy of Well Stimulation Permit; Notice of Availability for Water Testing, Sampling.

The Division should revise the radius within which surface property owners and tenants of legally recognized parcels of land must be notified to ensure that it is at least that specified by Section 1784(a)(2)(ii) (twice the anticipated well stimulation treatment radius). We recognize that the currently proposed radii of 1500 feet from the wellhead and 500 feet from the horizontal projection of the well were specified by SB 4, but the Division can and should go beyond these radii.

The well stimulation treatment radius analysis defines the minimum area in which groundwater may be endangered by injected fluids. As such, this is the appropriate radius within which to notify surface owners and tenants and to perform baseline water testing. The area around a stimulated well in which groundwater may be impacted depends on site-specific factors including the local geology and details of the stimulation treatment. Consequently, a fixed radius, including the proposed 1500 and 500 foot radii, is not appropriate. The radii in the statute have no scientific basis and do not sufficiently address endangerment of protected water by well stimulation.

A recent study has reported the maximum vertical height of induced hydraulic fractures as ~588 m (~1929 ft), with the probability of a fracture extending vertically more than 500 m (~1640 ft) being ~1%.[vi] In wells deeper than approximately 2000 ft, the maximum stress (overburden stress) is in the vertical direction and the least stress is in the horizontal direction. Induced fractures propagate perpendicular to least stress, meaning that they will be oriented vertically. Due to this stress regime, growth is constrained in the vertical direction and fractures tend to grow longer horizontally. This means that in deep wells, fracture length tends to be greater than fracture height.[vii]

A safety advisory from the British Columbia Oil and Gas Commission reports that communication has occurred between horizontal wellbores separated by up to 710m (~2345ft) and recommends coordination and monitoring of all drilling and completion activities in wellbores separated by 1000m (~3280 ft) or less.[viii]

Data show that induced hydraulic fractures can grow more than 1500 or 500 feet in both the vertical and horizontal directions. Furthermore, the pressure exerted by hydraulic fracturing and other forms of well stimulation can extend beyond the physical fractures or stimulated zone. A fixed radius is not appropriate and does not adequately address potential impacts to ground water. The notification and testing radius should be revised to match the radius in Section 1784(a)(2)(ii) (twice the anticipated well stimulation treatment radius).

With respect to notification methods and procedures, the Division should require the notice of availability of water sampling and testing to be translated into Spanish for communities that are reasonably known to be primarily Spanish-speaking, or other languages where it is reasonably known that English is not spoken as the primary language in that community or locale. In addition, in order to provide clarity for operators as well as the public, the Division may wish to offer a list of appropriate and acceptable methods of notification – such as personal service, certified mail, or the like – rather than leaving it to the discretion of the operator or its designee.

5.9 1783.3. Duty to Hire Independent Third Party to Provide Copy of Permit, Notice of Water Testing, Sampling.

5.9.1 1783.3(c)

The Division should provide guidance as to what type of information about the availability of water quality testing can be included in the notification, and provide a Division-run website or webpage where additional information can be found. This will help ensure that landowners and tenants have access to consistent information about the purpose and availability of water quality testing, and what the law and regulations require. Leaving the content entirely to the discretion of the operator may result in confusion, particularly if a landowner or tenant receives notices from multiple operators.

5.10 1784. Evaluation Prior to Well Stimulation Treatment.

5.10.1 1784(a)(1)

We support the Division's proposed requirement that operators must evaluate cement integrity prior to well stimulation, but suggest the following changes to the proposed requirements.
In order to ensure reliable measurements, the cement must be sufficiently hard before running a cement evaluation tool (CET), among other factors.[ix] In practice, the amount of time needed to ensure an accurate reading varies by site and depends on many factors including the cement formulation and the characteristics of the CET used.[x] We recommend revising the minimum wait time from 48 to 72 hours unless an ultrasonic cement analyzer (UCA) is used to more accurately determine the appropriate waiting-on-cement time.

The Division's current cementing requirements are not sufficient and therefore we object to the Division's proposal that the operator is only required to evaluate the cement that is required to be in place under Section 1722.4.

We object to the Division's proposal to allow the requirement to do a cement evaluation to be waived. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can compromise mechanical integrity, potentially leading well failure, or allow fluids to move behind casing from the reservoir into protected water. Verifying the placement of cement and cement bond is important and should be performed on every well.

We support the proposed requirement to run cement evaluation logs (CELs) on production casing but it is also crucial to verify the cement bond on other casing strings. CELs should be obtained for all strings of cemented casing that isolate protected water, potential flow zones, or through which stimulation will be performed (which can include production and intermediate casing).

We support the Division's proposed requirement that the cement evaluation must be submitted with the well stimulation application. This information is necessary to help the Division determine if the casing was cemented properly, so that any additional analysis or remedial operations that may be necessary to protect groundwater can be identified and implemented prior to stimulation.

(1) Allowing at least ~~48~~ <u>72</u> hours to elapse after cement placement, the operator shall run a radial cement evaluation log or other cement evaluation method that is approved by the Division and capable of demonstrating adequate cementing. <u>Cement evaluation logging must be performed on all strings of cemented casing that isolate protected water, potential flow zones, or through which stimulation will be performed. The Division may revise the wait-on-cement time if an ultrasonic cement analyzer (UCA) is used to more accurately determine the appropriate waiting-on-cement time.</u> If the quality of the cement outside ~~of the production~~ <u>any string of</u> casing is not sufficient to ensure the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation treatment, then the operator must develop a plan to remediate the cement and obtain approval from the Division for the remediation plan prior to proceeding. ~~The operator is only required to evaluate the cement that is required to be in place under Section 1722.4.~~ ~~The Division may waive the requirement of doing a cement evaluation if the supervisor is satisfied that, based on geologic and engineering information available from previous drilling or producing operations in the area where the well stimulation treatment will occur, well construction and cementing methods have been established that ensure that there will be no voids in the annular space of the well.~~

5.10.2 1784(a)(2)

We support the Division's proposed requirement to perform a well stimulation radius analysis. This analysis is crucial to ensure that any potential pathways by which injected or displaced fluids could reach groundwater are identified and remediated, if necessary. However, the proposed regulations are not sufficient and we believe the following revisions and additions are necessary to reduce the risks to groundwater.

5.10.2.1 1784(a)(2)(i)

We support the requirement to perform appropriate modeling to determine the well stimulation treatment area of influence (AOI). However, the rules should include additional specifics about what constitutes an "appropriate model." The rules should specify that operators are required to model the length, height, and orientation of fractures (in the case of fracture stimulation), horizontal and vertical penetration of stimulation fluids and proppant (if used), and horizontal and vertical extent of any displaced formation fluids. Operators should also model the volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids and chemical reaction byproducts over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

(1) Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated stimulation pressures, rates, and volumes;
(2) Geologic and engineering heterogeneities;
(3) Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations; and
(4) Cumulative impacts over the life of the project.

These standards are achievable with current technology and methods. Petroleum engineers routinely employ advanced computer modeling to simulate stimulation treatments.[xi]

5.10.2.2 1784(a)(2)(ii)

We support the requirement to identify potential migration pathways within the well stimulation treatment radius plus a safety factor. However, the safety factor should be twice the largest dimension anticipated by the AOI modeling, rather than twice the well stimulation treatment length. Depending on the specifics of the stimulation treatment, depth of the well, and other geologic and engineering factors, the length may not always be the greatest dimension of the AOI.

We support the proposed requirement to review all offset wells and faults within the well stimulation treatment radius plus a safety factor. However, the rules should require the operator to provide the Division with additional information about any such features identified and take additional steps to prevent communication with such features, including:

1. A list of all such wells, including but not limited to wells permitted but not yet drilled, drilling, awaiting completion, active, inactive, shut-in, temporarily abandoned, plugged, and orphaned.
2. A description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Division may require.
3. An assessment of the integrity of each well identified.

4. A plan for performing corrective action if any of the wells identified are improperly plugged, completed, or abandoned.
5. An assessment to determine the risk that the stimulation treatment will communicate with each well identified.
6. For each well identified as at-risk for communication, a plan for well control, including but not limited to:
    a. A method to monitor for communication
    b. A determination of the maximum pressure which the at-risk well can withstand
    c. Actions to maintain well control
    d. If the at-risk well is not owned or operated by the owner/operator of the well to be stimulated, a plan for coordinating with the offset well operator to prevent loss of well control.
7. The location, orientation, and properties of known or suspected faults, fractures, and joint sets
8. An evaluation of whether such features may act as migration pathways for injected fluids or displaced formation fluids to reach protected water or the surface
9. An assessment to determine the risk that the stimulation treatment will communicate with such features.
10. If such features may act as migration pathways and are at-risk for communication, the stimulation design must be revised to ensure that the treatment will not communicate with such features or the well must be re-sited.

This information should be provided with the stimulation permit application.

Communication between offset wells during stimulation is a serious problem, risking blow outs in adjacent wells and/or aquifer contamination during well stimulation. A New Mexico oil well recently experienced a blowout, resulting in a spill of more than 8,400 gallons of fracturing fluid, oil, and water. The blowout occurred when a nearby well was being hydraulically fractured and the fracturing fluids intersected this offset well.[xii] The incident led the New Mexico Oil Conservation Division to request information about other instances of communication between wells during drilling, completion, stimulation or production operations.[xiii] Incidents of communication between wells during stimulation have been documented in British Columbia[xiv], Pennsylvania[xv], Texas, and other states across the country.[xvi]

The Alberta Energy Regulator (AER), the oil and gas regulator in Alberta, Canada, recognized that communication between wells during fracturing is a serious risk to well integrity and groundwater after a number of spills and blowouts resulted from communication between wells during fracturing. As a result, AER created requirements to address the risk of communication and reduce the likelihood of occurrence.[xvii] Similarly, Enform, a Canadian oil and gas industry safety association, published recommended practices to manage the risk of communication.[xviii] We recommend that the Division review these rules and incorporate similar requirements.

5.10.2.3 1784(a)(2)(iii)

We object to the proposed requirement to exempt operators from reviewing the properties of geological formations adjacent to the productive horizon unless a radius of five times the anticipated well stimulation treatment length from a point of treatment extends beyond the productive horizon. This proposed rule appears to be a misinterpretation of the requirements of SB4 at 3160(i)(1)-(2). This section requires the operator to define a radius at least five times the fracture radius (for fracture stimulation treatments), and identify geologic features within that radius that may act as pathways or barriers for fluids to migrate outside the fractured zone. In other words, SB4 requires *all wells* that are fracture stimulated to have such an analysis performed.

It is important to assess the characteristics of rocks adjacent to the formation targeted for stimulation for all wells. Most crucial is to evaluate what can be termed the “confining zone,” defined as a geological formation, group of formations, or part of a formation above a zone that will be stimulated that is capable of limiting fluid movement above the stimulated zone. Operators should be required to demonstrate the presence of a suitable confining zone for all wells that will be stimulated, not only for fracture stimulated wells and not only for those wells where a radius of five times the anticipated well stimulation treatment length extends beyond the productive horizon.

We recommend the following revisions:

> ~~If a radius of five times the anticipated well stimulation treatment length from a point of treatment extends beyond the productive horizon being evaluated for possible well stimulation treatment, then the well stimulation treatment radius analysis shall include a review of the geological formations adjacent to the productive horizon.~~ Wells that will be stimulated must be sited such that a suitable confining zone is present. The owner or operator shall demonstrate to the satisfaction of the Division that the confining zone:
>
> 1. Is of sufficient areal extent to prevent the movement of injected or displaced fluids above the stimulated zone;
> 2. Is sufficiently impermeable to prevent the vertical migration of injected or displaced fluids;
> 3. Is free of transmissive faults or fractures that could allow the movement of injected or displaced fluids above the stimulated zone; and
> 4. Contains at least one formation of sufficient thickness and with geomechanical characteristics capable of preventing or arresting vertical propagation of fractures.
> 5. The Division may require the operator to identify and characterize additional zones that will impede or contain vertical fluid movement.
>
> The operator shall assess the mechanical rock properties, including permeability, relative hardness (using Young's Modulus), relative elasticity (using Poisson's Ratio), and other relevant characteristics of the geological formations to determine whether the geological formations will ensure the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation.

The results of this analysis should be submitted with the well stimulation application.

5.10.3 1784(a)(3)
We recommend the following additions:

(3) Utilizing the well stimulation treatment radius analysis conducted pursuant to subsection (a)(<u>2</u>~~4~~), the operator shall design the well stimulation treatment so as to ensure that the well stimulation treatment fluids or hydrocarbons do not migrate and remain geologically and hydrologically isolated to the hydrocarbon formation. <u>Elements of the well stimulation treatment design must include:</u>

<u>(i) The type (e.g. fresh water, brine, nitrogen, etc.) and source (e.g. stream, well, recycled flowback, etc.) of base fluid(s) to be used;</u>
<u>(ii) The estimated total volume of fluid and, if applicable, proppant to be used;</u>
<u>(iii) The anticipated surface treating pressure range;</u>
<u>(iv) The maximum anticipated pumping pressure;</u>
<u>(v) The operating procedure; and</u>
<u>(vi) The estimated or calculated fracture gradient of the producing and confining zone(s).</u>

5.11 1784.1. Pressure Testing Prior to Well Stimulation Treatment.
Pressure testing prior to well stimulation is critically important and we support the intent of the proposed requirements and also suggest the following additions.

5.11.1 1784.1(a)(1)
We support the proposed test pressure – including the incorporation of a safety factor – the test time and acceptable pressure loss.

The proposed rules fail to include testing standards for non-cemented completions. We suggest the following addition:

<u>Non-cemented production completions shall be tested to a minimum of (i) 70% of the lowest activating pressure for pressure actuated sleeve completions or (ii) 70% of formation integrity for open-hole completions, as determined by a formation integrity test.</u>

5.11.2 1784.1 (a)(2)
We support the proposed rule to test surface equipment and the proposed test pressure.

5.11.3 1784.1 (b)
The proposed regulations do not include a requirement to report the results of the pressure test. In addition to the regulations proposed, the Division should include the following additional requirements:

<u>(c) The results of the pressure test must be submitted to the Division prior to well stimulation. In the event of a failed test, the operator must orally notify the authorized officer as soon as</u>

practicable but no later than 24 hours following the failed test. Stimulation operations may not begin until a successful pressure test is performed and the results are submitted to the Division. If mechanical integrity cannot be restored, the well must be plugged and abandoned.

5.12 1785. Monitoring During Well Stimulation Treatment Operations.

Monitoring during well stimulation is crucial and we support the intent of proposed requirements but suggest the following additions and revisions.

5.12.1 1785(a)

(a) The operator shall continuously monitor and record all of the following parameters during the well stimulation treatment, if applicable:

(1) Surface injection pressure;

(2) Slurry rate;

(3) Proppant concentration;

(4) Fluid rate; ~~and~~

(5) All annuli pressures~~.~~; and

(6) Identities, rates and concentrations of additives used

5.12.2 1785(b)

(b) The operator shall terminate the well stimulation treatment and immediately provide the collected data to the Division if any of the following occur:

(1) A production-surface or intermediate-surface casing annulus pressure change of 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion;

(2) Pressure exceeding ~~90%~~ 80% of the API rated minimum internal yield on any casing string in communication with the well stimulation treatment;

(3) The operator has reason to suspect any potential breach in the production casing, production casing cement, or isolation of any sources of protected water~~.~~;

(4) Any monitored parameters indicate a loss or potential loss of mechanical integrity;

(5) Injection pressure exceeds the fracture pressure of the confining zone(s);

(6) Any indications that injected fluids or displaced formation fluids have contacted a transmissive fault or fracture or improperly constructed or plugged well;

(7) Communication occurs with an offset well.

5.12.3 1785(c)

(c) If any of the events listed in subdivision (b) occur, then the operator shall perform diagnostic testing on the well to determine whether a breach has occurred. Diagnostic testing shall be done as soon as is reasonably practical. The Division shall be notified when diagnostic testing is being done so that Division staff may witness the testing. All diagnostic testing results shall be provided to the Division. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the Division and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids above the stimulated zone has not been compromised.

5.12.4 1785(d)

(d) If diagnostic testing reveals that a breach has occurred, then the operator shall immediately shut-in the well, isolate the perforated interval, and notify the Division and the Regional Water Board with all of the following information:

(1) A description of the activities leading up to the well failure.

(2) Depth interval of the well failure and methods used to determine the depth interval.

(3) An exact description of the chemical constituents of the well stimulation treatment fluid, or of the fluid that is most representative of the fluid composition in the well at the time of the well failure, including:

(A) Total dissolved solids;

(B) Chloride, sodium, and all organic or inorganic chemicals listed in the tables in California Code of Regulations, title 14, sections 64431 and 64444; and

(C) Gross alpha, gross beta, uranium, tritium, radium 226+228, and all other radionuclides.

(4) An estimate of the volume of fluid lost during well failure.

(5) If available, groundwater quality data for the protected water closest to the well failure.

<u>If a loss of mechanical integrity is discovered, if the integrity of the confining zone has been compromised, or if fluids have reached a transmissive fault or communicated with an offset well, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released, or pose any risk of release into a source of protected water or any unauthorized zone, the operator must notify the Division immediately, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the Division. If such contamination occurs in a source of protected water that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publicly accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.</u>

5.12.5 1785(e)

We support these proposed requirements.

5.12.6 1785(f)

We support these proposed requirements.

5.13 1786. Storage and Handling of Well Stimulation Treatment Fluids.

We support the intent of the proposed requirements but the following revisions and additions are necessary to reduce potential impacts from the storage and handling of well stimulation fluids.

5.13.1 1786(a)

The proposed rules should explicitly state that these requirements cover flowback fluid. We support the requirement to store all fluids within secondary containment but the requirements of Section 1773.1 are not sufficient.

Numerous studies have identified flowback and produced water pits as one of the most common sources of environmental pollution from oil and gas operations. These pits pose a great risk to health and the environment even when they are lined. They can endanger surface water, groundwater, air, soil and wildlife. We therefore fully support the requirement to store fluids in tanks rather than sumps or pits. The rules should specify, however, that the tanks must be closed and watertight.

In the event of unauthorized releases, operators should also provide the location of the release, chemical composition of the release, fate of the released materials, and a description of any impacts or damages caused. Spill reports should also be made publicly available through the Division's website.

A manifest system should be used to track the transportation and ultimate disposition of all waste. Chemical composition of waste should also be determined in order to help guide the most appropriate method of disposal and in case of a release.

In sum, we propose the following revisions and additions to the proposed rules:

(a) Operators shall adhere to the following requirements for the storage and handling of well stimulation treatment fluid, additives, and produced water, including flowback fluid, from a well that has had a well stimulation treatment:

(1) Fluids shall be stored ~~in compliance with the secondary containment requirements of Section 1773.1, except that secondary containment is not required for portable or temporary production facilities.~~ within secondary containment. Secondary containment is required for all well stimulation equipment and material including flowback fluid tanks; waste handling tanks; fracture additive containers; and chemical and waste transport, mixing, and pumping equipment. Such secondary containment must be:

(A) Designed and constructed in accordance with good engineering practices;

(B) Constructed, coated or lined with materials that are chemically compatible with the environment and the substances to be contained;

(C) Provide adequate freeboard;

(D) Protected from heavy vehicle or equipment traffic; and

(E) Have a volume of at least 110 percent of the largest storage tank within the containment area.

(4) Fluids shall be stored in closed, watertight containers and shall not be stored in sumps or pits;

(6) Within 5 days of the occurrence of an unauthorized release, the operator shall provide the Division a written report that includes:
   (A) A description of the activities leading up to the release;
   (B) The type and volumes of fluid released;
   (C) The cause(s) of release;
   (D) Action taken to stop, control, and respond to the release; and
   (E) Steps taken and any changes in operational procedures implemented by the operator to prevent future releases.
   (F) The date, time, duration, and legal location of the release;
   (G) The common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and the best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations);
   (H) The actual or probable fate or disposition of the released fluid and any impacts or damages caused;

(9) A geochemical analysis must be performed on all flowback and produced water.
   (A) Analytes must include pH, conductivity, alkalinity, hardness, TDS, TSS, oil and grease, Al, As, Ba, Ca, Cd, Cl, Co, Cr, Cu, F, Fe, HCO3, K, Mg, Mn, Nitrate, Nitrite, Na, Ammonia, Ni, Pb, Se, SO4, Zn, TPH, GRO, DRO, BTEX, 2BE, Ra226, Ra228, RCRA characteristics (toxicity, ignitability, corrosivity, reactivity); and any other analytes required by the Division.
   (B) Flowback/produced water must be sampled with the following frequency:
      1. At the beginning of the flowback period;
      2. At the end of the flowback period;
      3. Monthly for the first five years thereafter or until there has been a 95% reduction in well stimulation treatment fluid contained in the produced fluid, whichever comes first.
   (C) The results of such analyses must be submitted to the Division no more than 30 days after analysis is performed. The Division will make the results available on its website no more than 5 days after receipt.

(10) If fluids will be transported offsite, the transporter must keep on each vehicle used to transport fluid a daily log and have it available upon the request of the Division or an authorized representative of the Division or a peace officer. The log shall, at a minimum, include all of the following information:

(A) The name of the owner or owners of the well or wells producing the fluid to be transported;
(B) The date and time the fluid is loaded;
(C) The name of the driver;
(D) The amount of fluid loaded at each collection point;
(E) The disposal, reuse or recycling location;
(F) The date and time the fluid is disposed of, reused, or recycled, and the amount of fluid disposed of, reused, or recycled at each location.

If any fluid is moved offsite by pipeline or other piping, the owner or operator must maintain a record of the date and time the fluid left the site, the quantity of fluid, and its intended disposition and use at each destination or receiving facility.

5.14 1787. Well Monitoring After Well Stimulation Treatment.

Ongoing monitoring and testing for mechanical integrity are critical to protecting the environment and we support the intent of the proposed provisions but suggest the following revisions and additions.

5.14.1 1787(a)

(a) Operators shall monitor each producing well that has had a well stimulation treatment at least weekly for any corrosion, equipment deterioration, hydrocarbon release or changes in well characteristics that could potentially indicate a deficiency in the wellhead, tree and related surface control equipment, production casing, intermediate casing, surface casing, tubing, cement, packers or any other aspect of well integrity necessary to ensure isolation of any underground sources of protected water and prevent any other health, safety or environmental issue. ~~to identify any potential problems with a well that could endanger any underground source of protected water or hydrocarbon zone.~~ If there is any indication of a lack of mechanical integrity of any well component ~~well failure~~, the operator shall immediately notify the Division and the Regional Water Board and perform diagnostic testing on the well to determine whether a deficiency does exist and the best method of repair. ~~well failure has actually occurred.~~ If the testing indicates that a loss of mechanical integrity ~~well failure~~ has occurred, then the operator shall immediately:

(1) T~~t~~ake all appropriate measures to prevent contamination of all underground sources of protected water, hydrocarbon zones, and all surface waters in the area of the well~~ and~~
(2) Commence remedial operations to restore mechanical integrity, and
(3) ~~shall~~ P~~p~~rovide the Division and the Regional Water Board with the information described in section 1785(d).

If the operator is not able to effectively restore mechanical integrity and/or implement a pressure maintenance plan to ensure the protection of all underground sources of protected water and the environment, the operator shall be required to immediately plug and abandon the well.

5.14.2 1787(b)

(a) The ~~production pressure of the~~ well shall be monitored ~~at least once every two days~~ daily for the first thirty days after the well stimulation treatment and on a monthly basis thereafter. ~~Information regarding production pressures~~ Monitoring reports shall be ~~reported~~ submitted to the Division on a monthly basis. Each monitoring report must include:

(A) The amount of oil, gas, and water produced, including the volume of readily identifiable well stimulation treatment fluid flowback;

(B) Flowing and shut-in tubing pressure;

(C) All annular casing pressures.

(b) ~~The well shall be monitored at least once every two days for the first thirty days after the well stimulation treatment and on a monthly basis thereafter to determine the amount of gas, oil, and water produced, including the volume of readily identifiable well stimulation treatment fluid flowback.~~ The operator shall report the ~~information~~ volume of readily identifiable well stimulation treatment fluid flowback to the Division on a monthly basis for 5 years or until there has been a 95% reduction in well stimulation treatment fluid contained in the produced fluid, whichever comes first, as determined by the geochemical analysis required in Section 1786(a)(9). All other monitored parameters shall be reported to the Division on a monthly basis for the life of the well.

(c) ~~The annular pressures of the well shall be reported to the Division annually.~~ It shall be immediately reported to the Division if annular pressure exceeds 70% of the API rated minimum internal yield or collapse strength of casing, or if surface casing pressures exceed a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet). The operator must take immediate action to remediate annular over-pressurization.

(d) The annular valve shall be kept accessible from the surface or left open and plumbed to the surface with a working pressure gauge ~~unless it has been demonstrated to the Division's satisfaction that there are no voids in the annular space~~.

5.15 1788. Required Public Disclosures.

The proposed requirements are insufficient to ensure public access to comprehensive information about each well stimulation treatment.

FracFocus.org, which the Department proposes to use as a temporary reporting site, is not bound by government requirements for records management, including protections against unauthorized alteration or deletion, and assurance that records will be available years in the future when problems arise. Additionally, the site erects needless hurdles to the usability of the data on the site. Data should be provided to the public in a format that is searchable and can be aggregated to allow researchers' and the public's to find, interpret and analyze information reported to the site. FracFocus provides no way for users to download its database in aggregate but only allows access to a single pdf document at a time. The FracFocus site's official Terms of Use also put unnecessary restrictions on public use, sharing, and aggregation of the data, purporting to prevent any copying, distribution, or transmission of public data. Therefore, the Division should ensure that it takes possession of all information provided to FracFocus in order to ensure that the information is available in the future, even if FracFocus is no longer operable. Additionally, the Division could easily make aggregate, searchable, machine-readable data available to the public itself by providing for regular download of FracFocus data and posting of the data on a public website. Significant concerns have also been raised with compliance and accuracy of data posted to FracFocus.org. The Division should include in its regulations a procedure for reviewing all information posted to the site to check submissions for accuracy and compliance with all rules.

The proposed regulations fail to fulfill the Division's statutory mandate under Cal. Pub. Resources Code § 3160(j)(10) to "develop a timely procedure" for the provision of trade secret information to health professionals and other parties. The Division should ensure, in developing these regulations, that each claim of trade secret is accompanied by a notice of a 24-hour telephone number where the information can be obtained. It is essential that parties such as health professionals, who may need trade secret information urgently, immediately know how to obtain the information and be able to request it without delay. The regulations should also set a specific time limit for providing the information to the requestor of at most one hour.

We suggest the following revisions and additions to the proposed contents of the required public disclosures:

(7) True vertical <u>and measured </u>depth of the well;

(12) The source, volume, and specific composition and disposition of all water associated with the well stimulation treatment, including, but not limited to, water used as base fluid and water recovered from the well following the well stimulation treatment that is not otherwise reported as produced water pursuant to Section 3227~~;~~. <u>Each water source should be reported separately and should include information on source type (oilfield produced or wastewater, municipal or industrial wastewater, surface water, groundwater, municipal water, or specify other source), source location, volume, supplier, whether the water has been treated or recycled, and, for groundwater, TDS content.</u>

(15) The location of the portion of the well subject to the well stimulation treatment<u>, the measured and true vertical depth of all perforations or the open-hole interval</u>, and the extent of the fracturing or other modification, if any, surrounding the well induced by the treatment.

(19) A complete list of the names, Chemical Abstract Service numbers, <u>volumes, </u>and maximum concentration, in percent by mass, of each and every chemical constituent of the well stimulation treatment fluids used. If a Chemical Abstract Service number does

not exist for a chemical constituent, the operator may provide another unique identifier, if available.

(b) If the Chemical Disclosure Registry is unable to receive information required to be reported under this section, then the operator shall provide the information directly to the Division.

(c) Except for items (1) through ~~(6)~~(8), (16), (17) & (18) of subsection (a), operators are not required to post information to the Chemical Disclosure Registry if the information is found in a well record that the Division has determined is not public record, pursuant to Public Resources Code section 3234. If information listed in subsection (a) is not posted to the Chemical Disclosure Registry on this basis, then the operator shall inform the Division in writing, specifying the information that is not being publicly disclosed. It is the operator's responsibility to post the information to the Chemical Disclosure Registry as soon as the information becomes public record under Public Resources Code section 3234.

(20) An updated estimate of the well stimulation treatment radius including the estimated true vertical depth to the top of the stimulated zone, using data collected during the stimulation the same model employed in Section 1784(a)(2).

(21) Initial well test information recording daily gas, oil and water rate, and tubing and casing pressure;

(f) Until the Division has completed development of its own reporting website, the Division shall download, at least once per week, all data related to well stimulation treatments in California, including all information reported under this section, from the Chemical Disclosure Registry. The division shall post this data in a machine-readable digital file format on the Division's public website within 48 hours of each download.

5.16 1789. Post-Well Stimulation Treatment Report.

We suggest the following revisions and additions to the proposed contents of the post-well stimulation treatment report.

5.16.1 1789(a)

(a) Within 30 ~~60~~ days after the cessation of a well stimulation treatment, the operator shall submit a report to the Division describing:

(1) The results of the well stimulation treatment;

(2) The pressures encountered during the well stimulation treatment; ~~and~~

(3) How the actual well stimulation treatment differs from what was anticipated in the well stimulation treatment design that was prepared under Section 1784(a)(3~~5~~)~~.~~; and

(4) The information monitored and recorded under Section 1785(a).

5.16.2 1789(b)

The proposed requirements are not sufficient to address the potential for induced seismicity related to well stimulation. Hydraulic fracturing has been confirmed or is suspected as the cause induced seismicity strong enough to be felt at the surface in a number of incidents.

- In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Two relatively large earthquakes, with magnitudes 2.3 and 1.5, and 48 smaller events occurred in the hours after several stages of the Preese Hall 1 well were fracture stimulated.[xix]
- A report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8, could have been induced by hydraulic fracturing.[xx]
- A total of 38 seismic events were recorded by the Canadian National Seismograph Network (CNSN) in the Etsho and Tattoo areas of the Horn River Basin between 2009 and 2011, ranging in magnitude from 2.2 to 3.8. After reviewing the locations, depths, and magnitudes of the earthquakes and comparing to the timing and location of hydraulic fracturing, the researchers concluded that fracturing resulted in slippage along pre-existing faults, which caused the earthquakes. In all but one case, the earthquakes occurred along faults that had not previously been mapped.

Induced seismicity can result in serious environmental and human health impacts identical to those caused by natural earthquakes, including property damage and injury. Fault movement may potentially endanger groundwater by creating or enhancing migration pathways between the zone being stimulated and underground sources of drinking water. Seismicity can also compromise wellbore integrity. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250 foot length.[xxi] Such damage could compromise the cement bond, allowing fluids to migrate up the back side of the casing to groundwater. Subsidence-induced earthquakes in California's Wilmington Oil Field damaged the casing of hundreds of wells.[xxii] Even in the absence of actual damage, induced seismic events will have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

We recommend that the Division, in in consultation with the California Geological Survey, develop regulations to address induced seismicity. Elements of the regulation should include:

- A requirement for the operator to evaluate the potential for induced seismicity. This should include an analysis of background seismicity, local geology including faults and tectonically active features, local and regional stress state, proposed stimulation practices, and nearby instances of induced seismicity. The results of this evaluation should be provided with the well stimulation treatment permit application.

- Requirements for operators to develop and implement a protocol for addressing induced seismicity, based on the results of the evaluation of the potential for induced seismicity. The Division should review chapter 6, 'Steps Toward A "Best Practices" Protocol,' of the National Academy of Sciences 2013 report on induced seismicity, "Induced Seismicity Potential in Energy Technologies."[xxiii]
- An appropriate "traffic light" control system for responding to an instance of induced seismicity associated with well stimulation. This traffic light control system should be a required element of the protocol to address induced seismicity.

6 Additional Regulation is Needed to Reduce Environmental Impacts

While we support the Division's efforts to update its rules, there are many additional improvements that must be made to California's rules to address the full range of environmental and human health risks associated with well stimulation, including well construction, air emissions, putting sensitive areas off limits to development, appropriate setbacks, and others. The technology used in oil and gas production has evolved rapidly but, unfortunately, regulation has not kept pace. California's current rules are outdated and insufficient to protect human health and the environment.

6.1 Well Construction

Proper well design and construction are crucial first step to ensuring long-term mechanical integrity. California's current well construction rules are outdated and inadequate and must be updated to reflect technological advancements in oil and gas extraction techniques. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Public Resources Code section 3160, subdivision (b), requires the Division to adopt regulations to ensure integrity of wells, well casings, and the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation treatments. Given the paramount importance of proper well construction in preventing potential impacts from well stimulation operations, we request that the Division incorporate the following revisions and additions to California's existing well construction rules into the current rulemaking.

6.1.1 1722.2. Casing Program.

<u>(a) </u>Each well shall have casing designed to provide anchorage for blowout prevention equipment and to seal off fluids and segregate them for the protection of all oil, gas, and freshwater zones. All casing strings shall be designed to withstand anticipated collapse, burst, <u>compressive, buckling, </u>and tension forces<u>, thermal effects, corrosion, erosion, and well stimulation pressure </u>with the appropriate design factor provided to obtain a safe operation. <u>The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.</u>

<u>(b) </u>Casing setting depths shall be based upon geological and engineering factors, including but not limited to the presence or absence of hydrocarbons, formation pressures, fracture gradients, lost circulation intervals, and the degree of formation compaction or consolidation. All depths refer to true vertical depth (TVD) below ground level.

(c) In areas where the depth to the lowest protected water is not known, operators must estimate this depth and provide the estimate with the application for a permit to drill. This depth should then be verified by running petrophysical logs, such as resistivity logs, after drilling to the estimated depth. If the depth to the deepest protected water is deeper than estimated, an additional string of casing is required. Surface casing must be of sufficient diameter to allow the use of one or more strings of intermediate casing. All instances of protected water not anticipated on the permit application must be reported including the formation depth and thickness and water flow rate, if known or estimated.

(d) A formation integrity test (FIT) must be performed immediately after drilling out of all surface and intermediate casing. The test should demonstrate that the casing shoe will maintain integrity at the anticipated pressure to which it will be subjected while drilling the next section of the well, no flow path exists to formations above the casing shoe, and that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down. If any FIT fails, the operator must contact the Division and remedial action must be taken to ensure that no migrations pathways exist. The casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

(e) All surface, intermediate, and production casing strings must stand under pressure until a compressive strength of 500 psi is reached before drilling out, initiating testing, or disturbing the cement in any way. In no case should the wait-on-cement (WOC) time be less than 8-hours.

(f) All surface, intermediate, and production casing strings must be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.5 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 80% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

6.1.2 1723.3. Casing Requirements.

(a) Conductor casing. This casing shall be cemented at or driven to a maximum depth of 100 feet. Exceptions may be granted by the appropriate Division district deputy if conditions require deeper casing depth. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, conductor casing should be fully cemented to surface. A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

(b) Surface casing. Surface casing must be set shallower than any hydrocarbon-bearing zones and at least 100' but not more than 200' below the deepest protected water. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of protected water.

(c) Intermediate casing. This casing may be required for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Casing setting depth must be based on local engineering and geologic factors and be set at least 100' below the deepest protected water, anomalous pressure zones, lost circulation zones, and other drilling hazards. Intermediate casing must be set to protect groundwater if surface casing was set above the base of protected water, and/or if additional protected water was found below the surface casing shoe. When intermediate casing is installed to protect groundwater, the operator shall set a full string of new intermediate casing to a minimum depth of at least 100 feet below the base of the deepest strata containing protected water and cement to the surface. The location and depths of any hydrocarbon strata or protected water strata that is open to the wellbore above the casing shoe must be confirmed by coring, electric logs or testing and shall be reported as part of the post-treatment report.

(d) Production casing. If both surface casing and intermediate casing are used as water protection casing, or if intermediate casing is not used, a full string of production casing is required. A production liner may be hung from the base of the intermediate casing and used as production casing as long as the surface casing is used as the water protecting casing and intermediate casing is set for a reason other than isolation of protected water. This casing shall be cemented and, when required by the Division, tested for fluid shutoff above the zone or zones to be produced. The test may be witnessed by a Division inspector. When the production string does not extend to the surface, at least ~~1~~200 feet of overlap between the production string and next larger casing string shall be required. This overlap shall be cemented and tested by a fluid-entry test at a pressure that is at least 500 psi higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations to determine whether there is a competent seal between the two casing strings. A pressure test may be allowed only when such test is conducted pursuant to an established field rule. The test may be witnessed by a Division inspector.

6.1.3 1722.4. Cementing Casing.

(a) Surface casing shall be cemented with sufficient cement to fill the annular space from the shoe to the surface by the pump and plug method.

(b) When intermediate casing is installed to protect groundwater, it must be fully cemented to surface. When intermediate casing is set for a reason other than to protect strata that contain protected water, it must be fully cemented to surface unless doing so would result in lost circulation. ~~Intermediate and production casings, i~~If not cemented to the surface, intermediate casing shall be cemented with sufficient cement to fill the annular space from the casing shoe to at least ~~5~~600 feet above fluid-bearing formations, lost circulation zones, oil and gas zones, ~~and~~ anomalous pressure intervals, or other drilling hazards. Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids. Sufficient cement shall also be used to fill the annular space to at least 100 feet above the base of the freshwater zone, either by lifting cement around the casing shoe or cementing through perforations or a cementing device placed at or below the base of the freshwater zone.

(c) When intermediate casing is not used, production casing must be fully cemented to surface unless doing so would result in lost circulation. If not cemented to the surface, production casing shall be cemented with sufficient cement to fill the annular space from the casing shoe to at least 600 feet above fluid-bearing formations, lost circulation zones, oil and gas zones, anomalous pressure intervals, or other drilling hazards. Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids. Sufficient cement shall also be used to fill the annular space to at least 100 feet above the base of the freshwater zone, either by lifting cement around the casing shoe or cementing through perforations or a cementing device placed at or below the base of the freshwater zone.

(d) All casing shall be cemented in a manner that ensures proper distribution and bonding of cement in the annular spaces. The appropriate Division district deputy may require a cement bond log, temperature survey, or other survey to determine cement fill behind casing. ~~If it is determined that the casing is not cemented adequately by the primary cementing operation, the operator shall recement in such a manner as to comply with the above requirements. If supported by known geologic conditions, an exception to the cement placement requirements of this section may be allowed by the appropriate Division district deputy.~~ If fluid returns, lift pressure, displacement and/or other operations indicate inadequate cement coverage, the operator must (i) run a radial cement evaluation tool, a temperature survey, or other test approved by the Division to identify the top of cement, (ii) submit a plan for remedial cementing to the Division for approval and (iii) implement such plan by performing additional cementing operations to remedy such inadequate coverage prior to continuing drilling operations.

(e) Prior to cementing the hole must be prepared to ensure an adequate cement bond by circulating at least two hole volumes of drilling fluid and ensuring that the well is static and all gas flows are killed. Top and bottom wiper plugs and spacer fluids must be used to separate drilling fluid from cement and prevent cement contamination. Casing must be rotated and reciprocated during cementing when possible and when doing so would not present a safety risk.

(f) Cement should be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus. During placement of the cement, operator shall monitor pump rates to verify they are within design parameters to ensure proper displacement efficiency.

Throughout the cementing process operator shall monitor cement mixing in accordance with cement design and cement densities during the mixing and pumping.

(g) All cemented casing strings must have a uniformly concentric cement sheath of at least 1" (i.e. minimum difference of 2" between wellbore diameter and casing outside diameter). An excess of 25% cement should be mixed unless a caliper log is run to more accurately determine necessary cement volume.

(h) All cement must have a have a 72-hour compressive strength of at least 1200 psi and free water separation of no more than two milliliters per 250 milliliters of cement, tested in accordance with the current API RP 10B. Cement must conform to API Specification 10A and gas-blocking additives must be used. Cement mix water chemistry must be proper for the cement slurry designs. At a minimum, the water chemistry of the mix water must be tested for pH prior to use, and the cement must be mixed to manufacturer's recommendations. An operator's representative must be on site verifying that the cement mixing, testing, and quality control procedures used for the entire duration of the cement mixing and placement are consistent with the approved engineered design and meet the cement manufacturer recommendations, API standards, and the requirements of this section.

(i) Compressive strength tests of cement mixtures without published performance data must be performed in accordance with the current API RP 10B and the results of these tests must be provided to the regulator prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

(j) For surface, intermediate, and production casing, at a minimum, centralizers are required at the top, shoe, above and below a stage collar or diverting tool (if used) and through all protected water zones. In non-deviated holes, a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to within one joint of casing from the bottom of the cellar, or casing shall be centralized by implementing an alternative centralization plan approved by the Division. In deviated holes, the Division may require the operator to provide additional centralization. All centralizers must meet API Spec 10D (Recommended Practice for Casing Centralizers – for bow string centralizers) or API Spec 10 TR4 (rigid and solid centralizers) and 10D-2 (Petroleum and Natural Gas Industries, Equipment for Well Cementing, Part 2, Centralizer Placement and Stop Collar Testing).

6.1.4 1744.6. Drilling Fluid Program—General.

(b) For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals.

6.2 Air Emissions (VOCs, Air Toxics, GHGs)

Air pollution from the oil and natural gas sector is a serious problem of nationwide scope that currently threatens the health of communities across the country. An expert panel advising the Department of Energy has long recommended concerted action to reduce these emissions.[xxiv] The Environmental Protection Agency (EPA) and several states have taken important first steps towards controlling harmful air pollution from the sector through national New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and through state rules.[xxv] Despite these steps, much more work remains to be done to protect communities and the climate from this pollution.

Flaring, venting, leaking and release of contaminants throughout the production, processing, transmission, and distribution systems are significant sources of air pollution from the oil and gas sector.[xxvi] One potentially large source of emissions during the production phase is the flowback period after well stimulation. These emissions can include hazardous and toxic air pollution as well as methane, a greenhouse gas with a global warming potential at least 28 times[xxvii] greater than carbon dioxide over the long-term, and 84 times greater over a 20-year horizon. EPA states that, "…light organics can be volatilized from recovered hydrocarbons or from solvents or other chemicals used in the production process for cleaning, fracturing, or well completion."[xxviii] These pollutants include but are not limited to alkanes, benzene, toluene, ethylbenzene, xylenes, and methanol.[xxix]

Although estimates vary, EPA's recently finalized NSPS will capture methane equivalent to about 21 million metric tons of CO_2 when fully implemented.[xxx] This leaves over 120 million metric tons CO_2e of methane venting and leaks to capture, or about 86% of sector emissions. Because methane often is emitted along with hazardous air pollutants and smog-forming VOCs, these remaining emissions also threaten local communities and regional air quality. The states have an array of tools that may aid in capturing or otherwise reducing these emissions. For example, Colorado recently proposed first-of-a-kind standards to reduce emissions of methane, VOCs, and hazardous air pollutants from the oil and gas industry.[xxxi] We have also produced a report, entitled "Leaking Profits," that outlines ten technically proven, commercially available, and profitable methane emission control technologies that together can capture more than 80 percent of the methane currently going to waste.

We request that the Division initiate a formal rulemaking process as soon as possible to create new rules to control air emissions from the oil and gas industry.

6.3 Prohibiting Development in Sensitive Areas

Oil and gas exploration and production in the United States has left behind a legacy of pollution and environmental impacts.[xxxii] Even with the strongest possible regulation and enforcement, the risk of environmental and human health impacts can never be completely eliminated.
Among the most commonly cited environmental impacts of oil and gas production are degradation of soils and water caused by releases of hydrocarbons and produced water.[xxxiii]

Contamination caused by releases of hydrocarbons and produced water can be extremely technologically and financially difficult to remediate, if not impossible. A multi-year, interdisciplinary study of hydrocarbon and produced water releases at an oil production site in Oklahoma undertaken by the United States Geological Survey (USGS) found that soil and groundwater at the site were still polluted after more than 60 years of natural attenuation.[xxxiv] Another multi-decade study by the USGS at the site of a crude oil spill in Minnesota found that contamination continues to persist after more than 30 years of natural attenuation and despite remediation attempts.[xxxv]

Given the serious and potentially permanent environmental impacts, oil and gas development should be completely prohibited in certain sensitive environments. The Division, in consultation with appropriate agencies, should identify categories of lands where development is prohibited.

6.4 Setbacks

Setbacks are essential to protect ground water, surface water, clean air, human health, wildlands and wildlife habitat. Setbacks should be based on scientific analysis and research. See attachment, "Comments of Miriam Rotkin-Ellman, MPH, Staff Scientist, Natural Resources Defense Council, Regarding Proposed Colorado Oil and Gas Conservation Commission Statewide Setbacks and Public Health" for additional information and recommendations.

7 Regulations of Other States Governing Oil and Gas and American Petroleum Institute (API) Recommended Practices

Other oil and gas producing states have adopted regulations that exceed the Division's existing and proposed regulations and that are consistent with our recommendations. A number of our recommendations above are also consistent with practices recommended by the American Petroleum Institute (API). No state consistently meets what NRDC considers to be best practices and each state's regulations have areas where they are weaker, so this should not be seen as an endorsement of the specific rules listed below or of any state's regulatory program. Although some of the regulations below fall short of the best practices we recommend in the comments above, we provide these examples to demonstrate that other states have stronger regulations than California's existing and proposed rules and also regulate categories of practice about which California's current regulations are completely silent.

- Sections 1761 and 1780: Wyoming regulates all forms of well stimulation without any thresholds. See, e.g.:
  - Approval must be sought to acidize, cleanout, flush, fracture, or stimulate a well. Weil's Code of Wyo. Rules, Oil and Gas Conserv. Comm'n, Gen. Agency, Bd or Comm'n Rules, ch. 3, § 1(a).
  - An approved Application for Permit to Drill (APD, Form 1) or an approved Sundry Notice (Form 4) is required prior to the initiation of any well stimulation activity. Weil's Code of Wyo. Rules, Oil and Gas Conserv. Comm'n, Gen. Agency, Bd or Comm'n Rules, ch. 3, § 45.
- Section 1784(a)(1): Colorado has more stringent requirements for cement bond logging by not allowing the requirement to be waived:

- A cement bond log shall be run on all production casing or, in the case of a production liner, the intermediate casing, when these casing strings are run. 2 Colo. Code Regs. § 404-1:317(g), § 404-1:317(o).

- Section 1784(a)(2)(ii): Alberta, Canada has requirements for preventing and mitigating communication during well stimulation, see Alberta Energy Regulator Directive 083: Hydraulic Fracturing – Subsurface Integrity
- Section 1784.1: Texas has pressure testing requirements for non-cemented completions and also requires failed tests to be reported to the regulator:
  - Casing strings that include a pressure actuated valve or sleeve shall be tested to 80 percent of actuation pressure for a minimum time period of five (5) minutes. 16 Tex. Admin. Code § 3.13(a)(7)(B).
  - The district director shall be notified of a failed test within 24 hours of completion of the test. In the event of a pressure test failure, no hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing). 16 Tex. Admin. Code § 3.13(a)(7)(B).
- Section 1785(c): In the event of excess pressure during stimulation, Texas requires the well to be remediated prior to further operations:
  - Further completion operations, including hydraulic fracturing treatment operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan. 16 Tex. Admin. Code § 3.13(a)(7)(C).
- Section 1786(a):
  - (6) Louisiana requires disclosure of the chemical composition of spills: The common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and the best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations); La. Admin. Code tit. 33, Part IX, § 708(C)(1)(iv); La. Admin. Code tit. 33, Part I, § 3901 et seq.
  - (10) Ohio requires manifesting of oil and gas waste: Each registered transporter shall keep on each vehicle used to transport brine a daily log and have it available upon the request of the chief or an authorized representative of the chief or a peace officer. The log shall, at a minimum, include all of the following information: (1) The name of the owner or owners of the well or wells producing the brine to be transported; (2) The date and time the brine is loaded; (3) The name of the driver; (4) The amount of brine loaded at each collection point; (5) The disposal location; (6) The date and time the brine is disposed of and the amount of brine disposed of at each location. Ohio Rev. Code. § 1509.223(C).

- Section 1722.2:
    - (d) The API recommends the use of formation pressure tests: Immediately after drilling out of the surface and intermediate casing plus a short interval of new formation below the surface or intermediate casing shoe, a formation pressure test (also known as a "shoe test" or "leak-off test") should be performed. If the test results of the formation pressure integrity test are inadequate or indicate a failure, remedial measures should be undertaken as appropriate. In particular, in the case of a failure, remedial cementing operations should be undertaken as appropriate. This is critical to maintaining well integrity. American Petroleum Institute. 2009. Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. API Guidance Document HF1. First Edition, October 2009.
    - (e) Alaska, Arkansas, the BLM, Colorado, Louisiana, Montana, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming all have requirements for waiting-on-cement time. The API also recommends that cement be allowed to set until sufficient compressive strength is achieved prior to commencing further operations.
    - (f) Alaska, the BLM, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming all have requirements for casing pressure testing. The API also recommends pressure testing prior to drill out.
- Section 1723.3:
    - (b):
        - The API recommends setting surface casing at least 100' below the deepest USDW: At a minimum, it is recommended that surface casing be set at least 100 feet below the deepest USDW encountered while drilling the well. American Petroleum Institute. 2009. Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. API Guidance Document HF1. First Edition, October 2009.
        - Wyoming requires surface casing to be set three joints below permitted water wells: Unless otherwise approved by the Supervisor, surface casing shall be set at a minimum of three (3) joints or approximately one hundred (100) to one hundred twenty (120) feet below the depth of any Wyoming Office of State Engineer permitted water supply wells designated for domestic, stock water, irrigation or municipal use, within a minimum of one-quarter (1/4) mile radius and shall be cemented to surface. Weil's Code of Wyo. Rules, Oil and Gas Conserv. Comm'n, Gen. Agency, Bd or Comm'n Rules, ch. 3, § 22(a)(i).
        - Texas requires surface casing to be set no more than 200 feet below protected water: An operator shall set and cement sufficient surface casing

to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. 16 Tex. Admin. Code § 3.13(b)1(B)(i).

- (d) Ohio requires 200 feet of overlap for production liners: Liners may be set and cemented as production casing, provided that the cemented liner has a minimum of 200 true vertical depth feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level that is at least 500 pounds per square inch higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. Ohio Admin. Code 1501:9-1-08(M)(7)(a)(i)-(iii).

- Section 1722.4:
  - (e) The API recommends proper hole conditioning and cleaning prior to cementing: Top and bottom wiper plugs should be used to minimize mixing of cement with drilling fluid while it is being pumped. Cement job design should include proper cement spacer design and volume. The operator should ensure proper wellbore preparation, hole cleaning, and conditioning with wiper trips prior to the cement job. Rotation and reciprocation of casing should be considered where appropriate to improve mud removal and cement placement. Service providers should ensure proper mixing, blending, and pumping of the cement in the field. American Petroleum Institute. 2009. Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. API Guidance Document HF1. First Edition, October 2009.
  - (g) Southwestern Energy, in comments to the Texas Railroad Commission on its Revised Proposed Rules for Drilling, Casing, Cementing, and Fracture Stimulation, recommended a wellbore diameter at least two inches greater than the nominal outside diameter of the casing. Southwestern cited multiple industry sources to support this recommendation. "Comments on Revised Proposed Rule 3.13 to Clarify Requirements for Drilling, Casing, Cementing, and Fracture Stimulation." James L. Bolander, Jr. 20 March 2013. available at < http://www.rrc.state.tx.us/rules/3-13-Feb2013-Bolander.PDF>
  - (h):
    - Ohio has requirements for meeting API cement standards and minimum compressive strength: All cement placed into the wellbore shall be Portland cement that is manufactured to meet the standards of API 10A

Specification for Cements and Materials for Well Cementing or ASTM C150/C150M Standard Specification for Portland Cement. The tail cement for all intermediate and production casings and liners shall remain static until the cement has reached a compressive strength of at least 500 psi before drilling out the plug or initiating a test. Tail cement shall have a 72-hour compressive strength of at least 1200 psi. Lead cements with volume extenders may be used to seal these strings, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed. Ohio Admin. Code 1501:9-1-08(J)(1)-(3).

- Texas has requirements for meeting API cement standards; controlling gas migration; and free water content and minimum compressive strength for cement behind surface casing: The base cement shall meet the standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement (or a Commission-approved equivalent standard). Where necessary, the cement slurry shall be designed to control annular gas migration consistent with, or equivalent to, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction. The cement mixture in the zone of critical cement1 shall have a 72-hour compressive strength of at least 1,200 psi. In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement. 16 Tex. Admin. Code § 3.13(a)(4)(B), § 3.13(b)(1)(D)(i), § 3.13(b)(1)(D)(iii).
- Wyoming has requirements for free water content of cement and minimum compressive strength: In addition, the API free-water separation for all cement slurries used shall average no more than four (4) milliliters per two hundred fifty (250) milliliters of cement. All cements used shall achieve a minimum compressive strength of one hundred (100) psi in twenty-four (24) hours measured at eighty degrees Fahrenheit (80˚ F.). Weil's Code of Wyo. Rules, Oil and Gas Conserv. Comm'n, Gen. Agency, Bd or Comm'n Rules, ch. 3, § 22(a)(ii).

- (i):
    - Texas has requirements for testing cement behind surface casing without published performance data: Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure. (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement. (ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater. 16 Tex. Admin. Code § 3.13(b)(1)(E).
    - The API recommends appropriate cement testing: Appropriate cement testing procedures should be properly carried out by the service company personnel (see API RP 10B-2). Cement slurry design should include testing to measure the following parameters depending on site-specific geologic conditions: 1) Critical Parameters - Recommended for all situations: slurry density, thickening time, fluid loss control, free fluid, compressive strength development, fluid compatibility (cement, mix fluid, mud, spacer); 2) Secondary Parameters - Recommended for use as appropriate to address specific well conditions: sedimentation control, expansion or shrinkage of set cement, static gel strength development, mechanical properties (Young's Modulus, Poisson's Ratio, etc.). American Petroleum Institute. 2009. Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. API Guidance Document HF1. First Edition, October 2009.
- (j): Texas has requirements for the use of centralizers on surface and production casing: Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In

> nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet specifications in, or equivalent to, API spec 10D Specifications for Bow-Spring Casing Centralizers; API Spec 10 TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations; and API RP 10D-2, Recommended Practice for Centralizer Placement and Stop Collar Testing. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation. 16 Tex. Admin. Code § 3.13(b)(1)(G), § 3.13(b)(3)(A).

8 Conclusion

We appreciate the Department's and the Division's consideration of our above technical comments regarding the proposed draft regulations for the use of well stimulation in oil and gas production in the state of California.

The possible impacts of hydraulic fracturing, acidizing, and other well stimulation on the local communities and natural resources of this state are severe, and it is the Department's and the Division's mandate to prevent, as far as possible, damage to public health, natural resources, and underground and surface waters. At this time, there is a statewide study investigating the potential risks and impacts of hydraulic fracturing and other well stimulation techniques underway as well as a CEQA related environmental review process of the same that has only just begun. We laud those efforts. However, until we fully understand the risks related to hydraulic fracturing and have safeguards in place to guard communities against those risks, we ask you to impose an immediate moratorium on terrestrial and offshore hydraulic fracturing, acidizing, and other forms of well stimulation.

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[i] *Compare* Cal. Code Regs §§ 1710-1724.10 (onshore well regulations) *with* Cal. Code Regs §§ 1740-1749 (offshore well regulations).

[ii] "SB 4 Well Stimulation Treatment Regulations, Initial Statement of Reasons." California Department of Conservation. Division of Oil, Gas, and Geothermal Resources. n.p. 15 Nov 2013. Web. 13 Jan. 2014.

[iii] "Senate Bill 4 Implementation Plan." California Department of Conservation. Division of Oil, Gas, and Geothermal Resources. n.p. n.d. Web. 13 Jan. 2014.

[iv] Wu, Y., Yin, X., Kneafsey, T., Miskimins, J., Cha, M., Patterson, T., Yao, B., Alqahtani, N.B., (2013) *Development of Non-Contaminating Cryogenic Fracturing Technology for Shale and Tight Gas Reservoir, Project Number: 10122-20*. Annual Report to Research Partnership to Secure Energy for America.

[v] Friedmann, S. Julio., "Transforming shale gas development and recovery through advanced technology" 26 Sept 2011. Online video clip. *University of Wyoming WyoCast On-Demand.* Accessed 9 Jan 2014. <http://wyocast.uwyo.edu/WyoCast/Play/86e345e0abc74d8da3ec3e6a3f9017ff1d>

[vi] Davies, R. J., Mathias, S. A., Moss, J., Hustoft, S., & Newport, L. (2012). Hydraulic fractures: How far can they go?. *Marine and petroleum geology*, *37*(1), 1-6.

[vii] Fisher, K., & Warpinski, N. (2012). Hydraulic-Fracture-Height Growth: Real Data. *SPE Production & Operations , 27* (1), 8-19.
[viii] "Safety Advisory 2010-03, May 20, 2010: Communication During Fracture Stimulation." BC Oil and Gas Commission. n.p. 20 May 2010. Web. 3 Jan. 2014.
[ix] Boyd, D., Al-Kubti, S. Khedr, O.H., Khan, N., Al-Nayadi, K., Degouy, D., Elkadi, A., and Al Kindi, Z., "Reliability of Cement Bond Log Interpretations Compared to Physical Communication Tests Between Formations." *Abu Dhabi International Petroleum Exhibition and Conference, 5-8 November 2006, Abu Dhabi, UAE.* Society of Petroleum Engineers, 2006. 11 pp.
[x] Jordan, M.E., and Shepherd, R.A., "Cement Bond Log: Determining Waiting-on-Cement Time." *SPE Annual Technical Conference and Exhibition, 22-26 September 1985, Las Vegas, Nevada.* Society of Petroleum Engineers, 1985. 8 pp.
[xi] See, e.g. Jones, J. R., & Britt, L. K. (2009). *Design and Appraisal of Hydraulic Fractures.* Society of Petroleum Engineers.; Adachi, J., Siebrits, E., Peirce, A., & Desroches, J. (2007). Computer simulation of hydraulic fractures. *International Journal of Rock Mechanics and Mining Sciences*, *44*(5), 739-757.
[xii] Jensen, Tina. "Fracking fluid blows out nearby well; Cleanup costs, competing technologies at issue". Kasa.com. 18 Oct. 2013: LIN Television Corporation. Web. 2 Jan. 2014.
[xiii] "Aztec District III-Request for information." State of New Mexico, Energy, Minerals and Natural Resources Department., n.p., 22 Oct. 2013. Web. 2 Jan. 2014.
[xiv] *Ibid.* endnote viii.
[xv] See, e.g. Detrow, Scott. (2012) "Perilous Pathways: How Drilling Near An Abandoned Well Produced a Methane Geyser." StateImpact Pennsylvania 9 October 2012: NPR. Web. 3 Jan. 2014.; Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management. (2009, October 28). Draft Report - Stray Natural Gas Migration Associated with Oil and Gas Wells.
[xvi] Vaidyanathan, Gayathri. "When 2 wells meet, spills can often follow." EnergyWire. 5 Aug. 2013: E&E News. Web. 3 Jan. 2014.
[xvii] Alberta Energy Board. (2013 May). Directive 083: Hydraulic Fracturing – Subsurface Integrity. 15p. available at http://www.aer.ca/documents/directives/Directive083.pdf
[xviii] Enform Canada. 27 Mar. 2013. "Interim IRP 24: Fracture Stimulation: Interwellbore Communication; An Industry Recommended Practice For The Canadian Oil And Gas Industry" Interim Volume 24. 1st Edition.
[xix] de Pater, C.J., and Baisch, S., 2011, *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd, 71p.
[xx] Holland, A., 2011, *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey, Open-File Report OF1-2011, 31p.
[xxi] *Ibid.* endnote xix
[xxii] Dusseault, M., Bruno, M., & Barrera, J. (1998, November). Casing shear: causes, cases, cures. In *SPE International Oil and Gas Conference and Exhibition in China*.
[xxiii] National Research Council. *Induced Seismicity Potential in Energy Technologies*. Washington, DC: The National Academies Press, 2013.
[xxiv] DOE, Secretary of Energy Advisory Board Shale Gas Production Subcommittee, Second Ninety Day Report (Nov.
18, 2011) at Annex C.
[xxv] See, e.g., Oil and Natural Gas sector: New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants Reviews, Final Rule 77 Fed. Reg. 49,490 (Aug. 16, 2012) (final NSPS and NESHAP, drawing heavily on work done by the states of Colorado and Wyoming).
[xxvi] See, e.g., Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards ("TSD") (2011) at 4-7, 5-6, 6-5, 7-9, 8-1.; see also Al Armendariz, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements (Jan. 26, 2009) at 24.
[xxvii] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Final Draft Underlying Scientific-Technical Assessment. [Jacob, D., Ravishankara, A.R., and Shine, K (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
[xxviii] US Environmental Protection Agency. (1987). *Report to Congress: Management of Wastes from the*

Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy, Volume 1 of 3: Oil and Gas.

[xxix] See, e.g. US Environmental Protection Agency. (2009). *Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1, Final Report.*; *Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking, Docket ID: EPA-HQ-OAR-2010-0505.* Retrieved August 29, 2012, from Docket: Oil and Natural Gas Sector – New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and Control Techniques Guidelines: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084

[xxx] See 77 Fed. Reg. at 49,492.

[xxxi] 5 CCR 1001-9 Regulation No. 7 Control Of Ozone Via Ozone Precursors (Emissions Of Volatile Organic Compounds And Nitrogen Oxides), 30 Colo. Reg. 23 (December 10, 2013) (To be codified at 5 CCR 1001-9)

[xxxii] Kharaka, Y. K., & Dorsey, N. S. (2005). Environmental issues of petroleum exploration and production: Introduction. *Environmental Geosciences , 12* (2), 61-63.

[xxxiii] *Ibid.*

[xxxiv] Kharaka, Y. K., & Otton, J. K., eds. (2003). *Environmental impacts of petroleum production - Initial results from the Osage-Skiatook Petroleum Environmental Research Sites, Osage County, Oklahoma.* U.S. Geological Survey Water-Resources Investigations Report 03-4260.

[xxxv] Essaid, H. I., Bekins, B. A., Herkelrath, W. N., & Delin, G. N. (2011). Crude oil at the Bemidji Site - 25 years of monitoring, modeling, and understanding. *Ground Water , 49* (5), 706-726.

ATTACHMENT I:

COMMENTS OF MIRIAM ROTKIN-ELLMAN, MPH
STAFF SCIENTIST
NATURAL RESOURCES DEFENSE COUNCIL
REGARDING PROPOSED COLORADO OIL AND GAS CONSERVATION COMMISSION STATEWIDE SETBACKS AND PUBLIC HEALTH

NATURAL RESOURCES DEFENSE COUNCIL

December 19, 2012

Comments of Miriam Rotkin-Ellman, MPH

Staff Scientist

Natural Resources Defense Council

Regarding Proposed Colorado Oil and Gas Conservation Commission Statewide Setbacks and Public Health

Health Concerns at Oil and Gas Facilities

Oil and gas production has increased dramatically in the United States and new technologies associated with hydraulic fracturing ("fracking") have expanded these operations into communities across the country. Hydraulic fracturing and oil and natural gas facilities have been identified as potentially significant sources of environmental contaminants and there is increasing concern about threats to public health. In April 2012, the National Institute of Medicine (IOM) convened a two day workshop of public health experts which included more than a dozen presentations describing the health implications from natural gas development.[1] Additionally, investigations of risks from individual sites, practices, and environmental media have been conducted by government agencies including the Agency for Toxic Substances Disease Registry (ATSDR) within the Department of Health and Human Services (HHS) and the US Environmental Protection Agency.[2] [3] Health-related advisories and informational resources have been made available from the National Institute for Occupational Safety and Health

[1] Institute of Medicine. 2012. Workshop on the Health Impact Assessment of New Energy Sources: Shale Gas Extraction. April 30-May 1, 2012. Washington, DC. http://www.iom.edu/Activities/Environment/EnvironmentalHealthRT/2012-APR-30.aspx

[2] Masten, S. 2012. HHS & NIEHS Activities Related to Hydraulic Fracturing and Natural Gas Extraction. Presentation made at the 2012 Shale Gas Extraction Summit: October 2, 2012. http://environmentalhealthcollaborative.org/images/ScottPlenary.pdf

[3] United States Environmental Protection Agency (US EPA). 2012. EPA's Study of Hydraulic Fracturing and Its Potential Impact on Drinking Water Resources. http://www.epa.gov/hfstudy/

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(NIOSH) and the Occupational Safety and Health Administration (OSHA) [4] and the Pediatric Environmental Health Specialty Units (PEHSU).[5]

Air Pollution from Oil and Gas Facilities

The production, processing, storage and transmission of oil and natural gas, along with the practices specific to hydraulic fracturing, can release pollutants into the air with health consequences at the local, regional and global level. Pollution control technologies are needed to curb emissions of methane, a potent greenhouse gas that contributes to global climate change, and volatile organic compounds (VOCs) and nitrous oxides (NOx), which lead to unhealthy levels of regional ground-level ozone. At the local level, oil and natural gas facilities can threaten the health of nearby communities due to the releases of three different types of air pollution.

Diesel Particulate Matter (PM)

Exposure to diesel particulate matter (PM) is a known health hazard and the heavy use of diesel engines in and around oil and natural gas sites (particularly where hydraulic fracturing is being deployed) has raised concerns about unsafe exposures. Sources of diesel PM include truck traffic, drill rigs, pumps and other extraction and construction equipment.[6] A recent workplace health and safety investigation conducted by the National Institute for Occupation Safety and Health (NIOSH) concluded that diesel PM is a "likely health hazard" for workers at fracking sites. Out of the 11 sites tested in this investigation, 7 were in Colorado and testing in the Denver-Julesberg (DJ) basin of Colorado found 23% of samples above levels of concern for workers. [7] Given the proximity of these sites to homes, worksite health hazards are likely also problems for community members. The health impacts of diesel pollution are well characterized in the scientific literature and include cancer, respiratory and cardiovascular impacts, premature mortality and adverse birth outcomes.[8] Adverse respiratory and cardiovascular impacts have

[4] Occupational Safety and Health Administration (OSHA) 2012. Hazard Alert, Worker Exposure to Silica During Hydraulic Fracturing. www.osha.gov/dts/hazardalerts/hydraulic_frac_hazard_alert.html

[5] Pediatric Environmental Health Specialty Units and the American Academy of Pediatrics. 2011. PEHSU Information on Natural Gas Extraction and Hydraulic Fracturing for Health Professionals. http://aoec.org/pehsu/documents/hydraulic_fracturing_and_children_2011_health_prof.pdf

[6] Robinson AL. 2012 Air Pollutant Emissions from Shale Gas Development and Production. IOM Roundtable: The Health Impact Assessment of New Energy Sources: Shale Gas Extraction. April 30-May 1, 2012

[7] Esswein E et al 2012. NIOSH Field Effort to Assess Chemical Exposures in Oil and Gas Workers: Health Hazards in Hydraulic Fracturing. Presentation made at IOM Roundtable: The Health Impact Assessment of New Energy Sources: Shale Gas Extraction. April 30-May 1, 2012

[8] HEI Panel on the Health Effects of Traffic-Related Air Pollution. 2010. Traffic-Related Air Pollution: A Critical Review of the Literature on Emissions, Exposure, and Health Effects. HEI Special Report 17. Health Effects Institute, Boston, MA.

been demonstrated as resulting from both acute and chronic exposures.[9] Diesel PM levels are known to decrease rapidly with distance from sources of diesel emissions.[10]

Silica:

Hazardous levels of silica exposure for workers have been documented at fracking sites.[11] As a result, NIOSH has issued an Occupational Health Safety Alert. Silica exposures result from clouds of respirable silica dust created during the handling of fracking sands at fracking sites. The proximity of fracking sites to homes and people has raised questions about the potential for community exposures to unsafe levels of silica. Unsafe silica exposure is known to cause silicosis and lung cancer.[12]

Air Toxics:

A whole suite of volatile organic compounds (VOCs) can be present in the gas and liquids brought to the surface during oil and natural gas development. Many of these VOCs are known carcinogens and/or respiratory, neurological, developmental, and reproductive toxicants and others have yet to be characterized for their health impacts. These compounds are released to the air when the wells are drilled and fracked, through leaks or venting throughout the production and transmission system, and through evaporation from waste pits. Once released into the air, these compounds present an inhalation hazard to workers and community members in the vicinity of the facilities. Peer-reviewed studies conducted in Colorado are at the forefront of the scientific literature documenting the contribution of oil and gas facilities to air contaminants and the associated health risks.

USEPA's inventory of hazardous air pollutants released from oil and natural gas production and processing facilities includes eight carcinogens, seven pollutants which harm the respiratory system, eight pollutants which harm the nervous system, five reproductive/developmental toxicants, and other pollutants toxic to the liver, kidney, cardiovascular and immune system, and this list does not include emissions from oil or gas wells or wastewater pits.[13] Although comprehensive monitoring data near oil and gas facilities is lacking, the monitoring conducted in local and state investigations has detected these compounds in the air near residences and in some cases, at levels that exceed health-based standards.[14] [15] [16] [17]

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[9] US EPA. Diesel Particulate Matter – Health Effects. http://www.epa.gov/region1/eco/airtox/diesel.html

[10] California EPA 2005. Air Quality and Land Use Handbook: A Community Health Perspective http://www.arb.ca.gov/ch/handbook.pdf

[11] Esswein E et al 2012. NIOSH Field Effort to Assess Chemical Exposures in Oil and Gas Workers: Health Hazards in Hydraulic Fracturing. Presentation made at IOM Roundtable. : The Health Impact Assessment of New Energy Sources: Shale Gas Extraction. April 30-May 1, 2012

[12] Occupational Safety and Health Administration (OSHA) 2012. Hazard Alert, Worker Exposure to Silica During Hydraulic Fracturing. www.osha.gov/dts/hazardalerts/hydraulic_frac_hazard_alert.html

[13] USEPA 2012 National Emission Standards for Hazardous Air Pollutants (NESHAP): Oil and Natural Gas Sector

[14] ATSDR, Health Consultation: Public Health Implications of Ambient Air Exposures to Volatile

In the past six months, two groundbreaking peer-reviewed studies have been published which demonstrate air quality impacts from volatile organic compounds near oil and natural gas facilities. In a study published in the *Journal of Geophysical Atmospheres* and titled, "Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study." Pétron et al. determined that the emissions from oil and gas facilities in the study area (Front Range of Colorado) were likely responsible for increased levels of hydrocarbons, and benzene in particular, measured at both the stationary and mobile testing sites. Second, the authors concluded that the available inventories of hydrocarbon emissions from oil and gas facilities in the study area did not correlate with observed atmospheric observations and were likely underestimates. The authors note that the increase in hydraulic fracturing in the study area may be contributing to the pollution levels documented in the study.[18]

In the second study, titled "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources" and published in Science of the Total Environment, the researchers reported elevated levels of hydrocarbons in the ambient air at a fixed monitoring site located among rural homes, ranches, and natural gas developments sites. They also found that concentrations were, generally, higher at sampling sites closer to hydraulically fractured well pads.[19] For example, median xylene levels were found to be 9 times greater in the samples taken closer to the wells. Using standard risk assessment methodology, the researchers found that the measured levels of hydrocarbons correspond to elevated cancer and non-cancer risks, particularly those associated with levels measured near well pads. Elevated non-cancer hazard indices include neurological, respiratory, and hematologic impacts and estimated cancer risks exceed 1 in a million. The researchers also note that the health risks they estimated are consistent with subchronic health effects, such as headaches and throat and eye irritation, reported by residents during nearby natural gas development activities and hydraulic fracturing in particular.

Air Pollution and Health Risks Increase with Proximity to Sources

Taken together, the available research and testing data demonstrate that oil and natural gas facilities can be sources of air pollutants which threaten human health. Although the research specific to oil and gas continues to build on the strong findings in Colorado, there is also

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Organic Compounds as Measured in Rural, Urban, and Oil & Gas Development Areas Garfield County Colorado (2008);

[15] Witter R, McKenzie L, Towle M, Stinson K, Scott K, Newman L, Adgate J, 2010. Draft Health Impact Assessment for Battlement Mesa, Garfield County Colorado

[16] Wolf Eagle Environmental. 2009. Town of DISH Texas Ambient Air Monitoring Analysis Final Report

[17] ERG 2011. City of Fort Worth Natural Gas Air Quality Study

[18] Petron G et al 2012. Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study. Journal of Geophysical Atmospheres

[19] McKenzie LM et al 2012. Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources. Sci Total Environ. 2012 May 1;424:79-87.

considerable evidence from other industries and practices which release the same types of pollutants that demonstrates how the risks of health impacts are closely linked to proximity. For example, an investigation by the California EPA found that the level of diesel contamination decreased substantially with distance from a major source of diesel emissions - Eighty percent of diesel contamination was lost by 1,000 feet from the source and nearly 99 percent by 2,000 feet.[20]

A review of the available research on air pollution and health impacts at schools also finds higher levels of pollutants and health risks at schools closer to pollutant sources. These studies include the following findings: Spektor et al (1991) recorded impaired lung function in children attending schools with high particulate levels and found higher levels and greater respiratory problems with proximity to the pollution source (schools were located 100m - 1km (328 -3,280 feet) from the source).[21]; Mohai et al (2011) found an association between increasing air pollutant levels and poor school performance (schools included in this analysis were located within 2 km (1.2 miles) of industrial sources).[22]; Sanchez-Guerra et al (2012) measured pollutant levels and DNA damage and found higher levels associated with proximity to pollutant sources (schools were located within 5 km (3.1 miles) of industrial and mobile pollution sources.[23]

Other Health Risks Also Increase with Proximity

In addition to the air and water contamination issues, fracking sites pose a number of additional health threats for workers and communities. There is a considerable explosive hazard at these sites and there have been a number of worker fatalities in recent years. Traffic accidents have claimed the lives of more than 300 workers servicing fracking sites over the past decade and threaten community safety, as large trucks make more and more use of small, rural roads not intended for industrial traffic.[24] Noise and light pollution at drilling sites and along roads have also been identified as both nuisance and health threats.[25] Increased seismic activity resulting from wastewater injection also presents a health threat.[26]

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[20] California EPA 2005. Air Quality and Land Use Handbook: A Community Health Perspective http://www.arb.ca.gov/ch/handbook.pdf

[21] Spektor DM, Hofmeister VA, Artaxo P, et al. Effects of heavy industrial pollution on respiratory function in the children of Cubatao, Brazil: a preliminary report. Environ Health Perspect 1991;94:51-4.

[22] Mohai P, Kweon BS, Lee S, Ard K. Air pollution around schools is linked to poorer student health and academic performance. Health Aff (Millwood) 2011;30(5):852-62.

[23] Sanchez-Guerra M, Pelallo-Martinez N, Diaz-Barriga F, et al. Environmental polycyclic aromatic hydrocarbon (PAH) exposure and DNA damage in Mexican children. Mutat Res 2012;742(1-2):66-71.

[24] Ian Urbina. Deadliest Danger Isn't at the Rig but on the Road. NY Times. May 14, 2012.

[25] Whitter R. 2012. Community Impacts of Natural Gas Development and Human Health. Presentation made at IOM Roundtable: The Health Impact Assessment of New Energy Sources: Shale Gas Extraction. April 30-May 1, 2012

[26] Frohlich C. Two-year survey comparing earthquake activity and injection-well locations in the Barnett Shale, Texas. PNAS online (ahead of print August 6, 2012) doi: 10.1073/pnas.1207728109 (PNAS August 6, 2012

Populations Vulnerable to Air Pollution Need Extra Protection

In addition to proximity, underlying characteristics can increase an individual and population's vulnerability to air pollution. There is a significant body of literature describing increased vulnerability to air pollution due to age and underlying health status. This research has found that children are more vulnerable to air pollution for the following reasons: pound for pound children take in more air than adults and therefore get a higher dose of contaminants; children's bodies are still developing and contaminant exposures can disrupt normal development resulting in disability and disease; exposure to carcinogens early in life can result in an increased risk of developing cancer[27]; children's play activities bring them in contact with pollutants (i.e. more time outside).[28] Underlying health problems, such as respiratory (including asthma) or cardiovascular disease, can make individuals, including adults, more likely to experience health impacts from air pollution.[29]

Policies to protect vulnerable populations

In response to the literature on increased susceptibility of vulnerable populations and the increased risk from air contaminants due to proximity, environmental and health policies have sought to increase public health protections by ensuring the physical separation of sources of air pollution from sensitive populations. In California, the Environmental Protection Agency (CalEPA) has defined the populations and sites that need extra protection from air pollution:

> "Sensitive individuals refer to those segments of the population most susceptible to poor air quality (i.e., children, the elderly, and those with pre-existing serious health problems affected by air quality)."
>
> Sensitive Sites are "land uses where sensitive individuals are most likely to spend time" and include, schools, schoolyards, playgrounds, parks, medical facilities, homes, and residential communities.[30]

To achieve these protections, the California EPA and local air pollution control agencies have published guidelines which include the following recommended separation distances:

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[27] US EPA. 2005. Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens. EPA/630/R-03/003F

[28] US EPA. 2012. Office of Children's Health Protection. http://yosemite.epa.gov/ochp/ochpweb.nsf/content/homepage.htm

[29] California EPA 2005. Air Quality and Land Use Handbook: A Community Health Perspective http://www.arb.ca.gov/ch/handbook.pdf

[30] California EPA 2005. Air Quality and Land Use Handbook: A Community Health Perspective http://www.arb.ca.gov/ch/handbook.pdf

- 1,000 ft to ¼ mile from sources of toxic air pollution, such as benzene and other VOCs
- 500 to 1,000 ft from sources of diesel pollution.[31] [32]

The California Department of Education has also reviewed the science and made recommendations for school locations to be located at least ¼ mile or 1,430 ft from sources of toxic air pollution.[33] Across the country, states and local governments have been reviewing the question of setbacks from natural gas facilities and these jurisdictions have implemented setbacks up to 1,500 feet.

Policies to separate sensitive populations from sources of air pollution are a critical component of health protective policies. In order to protect public health, it is essential that policies reflect known relationships between contaminant releases and distance and the increased susceptibility of children and the elderly to air pollution. These policies must provide additional protections for vulnerable populations, address community concerns and take action to prevent unsafe exposures.

Conclusions

The research, monitoring data, and public health expertise available to date indicate that oil and natural gas facilities produce air pollution that can increase health risks. These risks increase with proximity, particularly for populations more vulnerable to the impacts of air pollution, which include children, elderly, and those with underlying health problems. In addition, proximity to these facilities can also subject individuals to light and noise pollution and increases health and safety risks from explosions and other malfunctions. There is ample evidence from Colorado, and other states, to justify action by policy makers to protect Colorado's families and communities from adverse health impacts and reduce the dangers of living in proximity to oil and gas operations. Colorado scientists have led the way in documenting air quality and public health impacts at oil and gas sites and their findings demonstrate that existing setback distances do not currently provide sufficient protection for vulnerable populations and should be strengthened. Protecting public health requires proactive policies which prevent exposures that can harm the health of individuals and communities. Separating vulnerable populations from sources of air pollution, and other hazards, is a key policy tool to ensure public health and safety and should be an integral part of policies aimed at reducing the health threats at oil and gas facilities. Pollution control measures and best management practices alone do not provide sufficient protection to guard against the hazardous exposures resulting from equipment failures,

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[31] California EPA 2005. Air Quality and Land Use Handbook: A Community Health Perspective http://www.arb.ca.gov/ch/handbook.pdf

[32] South Coast Air Quality Management District. 2007. Air Quality Issues in School Site Selection Guidance Document. http://www.aqmd.gov/prdas/aqguide/doc/School_Guidance.pdf

[33] California Department of Education. School Site Selection and Approval Guide. http://www.cde.ca.gov/ls/fa/sf/schoolsiteguide.asp

upsets, accidents, and uncontrolled emissions and must be coupled with sufficient setback requirements to adequately prevent adverse health impacts.

Setbacks of at least 1,000 feet coupled with pollution control requirements, including green completions and odor and dust control measures, are an essential step towards protecting Colorado residents and preventing adverse health impacts.

Sincerely,

Miriam Rotkin-Ellman, MPH

Staff Scientist

Natural Resources Defense Council

Key Studies/Experts Referenced

Author	Title	Journal or Conference Title	Date	Publication Type	Author Expertise
Robinson AL	Pollutant Emissions from Shale Gas Development and Production	Institute of Medicine Roundtable	2012	Expert Presentation	Ph.D. - Professor Engineering and Public Policy Mechanical Engineering Carnegie Mellon University
Esswein E	NIOSH Field Effort to Assess Chemical Exposures in Oil and Gas Workers: Health Hazards in Hydraulic Fracturing	Institute of Medicine Roundtable	2012	Expert Presentation	MSPH - Senior Industrial Hygienist, National Institute for Occupational Safety and Health (NIOSH),Centers for Disease Control and Prevention
ATSDR	Health Consultation: Public Health Implications of Ambient Air Exposures to Volatile Organic Compounds as Measured in Rural, Urban, and Oil & Gas Development Areas Garfield County Colorado	NA	2008	Agency Report	The Agency for Toxic Substances and Disease Registry (ATSDR), based in Atlanta, Georgia, is a federal public health agency of the U.S. Department of Health and Human Services. ATSDR serves the public by using the best science, taking responsive public health actions, and providing trusted health information to prevent harmful exposures and diseases related to toxic substances.
Witter R	Draft Health Impact Assessment for Battlement Mesa, Garfield County Colorado	NA	2010	Health Assessment	M.D., M.S.P.H., M.S. ---- Assistant Research Professor,Environmental and Occupational Health, Colorado School of Public Health

Wolf Eagle Environmental	Town of DISH Texas Ambient Air Monitoring Analysis Final Report	NA	2009	Air Monitoring Data Report	Wolf Eagle Environmental has been providing environmental services to a diverse group of Clients since 2004. Wolf Eagle is an EPA contract participant on EPA's Scientific Technical Research, Engineering and Modeling Support (STREAMS) and Resource Conservation and Recovery Act (RCRA) – RCRA Enforcement and Permitting Assistance (REPA 4- Zone 2 Regions 6&7).
Eastern Research Group (ERG) Inc.	City of Fort Worth Natural Gas Air Quality Study	NA	2011	Air Monitoring Data Report	ERG offers multidisciplinary skills in more than 20 specialized service areas. We use our expertise in these areas to help clients plan, research, develop, implement, promote, and assess their programs and projects. Our skills are used by a broad spectrum of clients, including federal agencies, state governments, corporations, and universities. Our services support our work in 11 key markets , or topic areas. We also operate and maintain a fully accredited laboratory in Research Triangle Park, North Carolina.
Petron G	Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study	Journal of Geophysical Atmospheres	2012	Peer-reviewed publication	PhD - Cooperative Institute for Research in Environmental Sciences, University of Colorado at Boulder, Boulder, Colorado, USA. Earth System Research Laboratory, National Oceanic and Atmospheric Administration, Boulder, Colorado, USA.

McKenzie LM	Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources	Science of the Total Environment	2012	Peer-reviewed publication	PhD MPH - Researcher University of Colorado School of Public Health
Spektor DM	Effects of heavy industrial pollution on respiratory function in the children of Cubatao, Brazil	Environmental Health Perspectives	1991	Peer-reviewed publication	Institute of Environmental Medicine, New York University Medical Center
Mohai P	Air pollution around schools is linked to poorer student health and academic performance	Health Affairs	2011	Peer-reviewed publication	PhD - Professor University of Michigan School of Natural Resources and Environment
Sanchez-Guerra M	Environmental polycyclic aromatic hydrocarbon (PAH) exposure and DNA damage in Mexican children	Mutation Research	2012	Peer-reviewed publication	Departamento de Toxicología, CINVESTAV-IPN, Mexico
Whitter R	Community Impacts of Natural Gas Development and Human Health. Presentation made at IOM Roundtable: The Health Impact Assessment of New Energy Sources: Shale Gas Extraction	Institute of Medicine Roundtable	2012	Expert Presentation	M.D., M.S.P.H., M.S. ---- Assistant Research Professor,Environmental and Occupational Health, Colorado School of Public Health

Frohlich C	Two-year survey comparing earthquake activity and injection-well locations in the Barnett Shale, Texas	PNAS	2012	Peer-reviewed publication	PhD - Associate Director, Senior Research Scientist Institute for Geophysics, Jackson School of Geosciences, University of Texas at Austin

Bio for Miriam Rotkin-Ellman, MPH

Miriam Rotkin-Ellman is a scientist with the Natural Resources Defense Council's (NRDC) health and environment program. Prior to joining NRDC in 2006, Miriam was an Environmental Scientist with the New Mexico Environment Department. Miriam's work includes researching the links between global warming and health, reducing air pollution from industrial sources, and protecting communities from pesticides and other toxics. She has worked with community groups to investigate, air quality and soil contamination in New Orleans following Hurricane Katrina, mercury contamination downwind from cement plants, health threats stemming from the BP oil spill in the Gulf of Mexico, and gaps in environmental enforcement in California. Her other research areas include, analysis of morbidity associated with the 2006 California heat wave, children's exposures to pesticides from the use of flea control products, and community vulnerability to climate change-related health threats.

Miriam is the author of 7 journal publications and 9 reports. She has presented her work for academic, professional, and lay audiences including, the annual meeting of the American Public Health Association, the Council of State and Territorial Epidemiologists, lectures at UC San Francisco and UC Berkeley, and community meetings. She is an active member of the California Climate Action Team - Public Health Workgroup and has participated in the Deep South Center for Environmental Justice's Public Policy Taskforce and as an advisor to the California Environmental Public Health Tracking program. Miriam earned her masters in public health (MPH) in Environmental Health Sciences from U.C. Berkeley in 2006 and a BS in Environmental Sciences with Honors from Brown University in 2000.

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Employment

Natural Resources Defense Council (NRDC): Staff Scientist — December 2006-present
Conduct research and investigation into priority environmental hazards including, global warming, pesticides, toxic air pollution and industrial waste contamination. Serve as a technical resource for community environmental health campaigns and investigations. Advocate for policy changes to improve laws and regulations to protect health. Represent NRDC in the press, agency hearings, community meetings, and public fora. Responsible for supervision of 1 staff member and numerous interns, students, and consultants.

Natural Resources Defense Council (NRDC): Graduate Student Intern & Consultant — Summer 2005-Summer 2006
Conducted background research, data collection and analysis, and report development for projects addressing mercury clean-up in the SF Bay, enforcement of environmental regulations, contamination from Hurricane Katrina, environmental and health impacts of goods-movement.

UC Berkeley Center for Environmental Public Health Tracking: Graduate Student Researcher — Fall 2004-Summer 2006
Conducted research on methods and approaches to better understand the relationship between environmental factors and disease through the development of an environmental public health surveillance system. Specific research topics include developing a tracking network for drinking water quality and using biomonitoring to conduct public health surveillance.

New Mexico Environment Department: Environmental Scientist — Spring 2001-Summer 2004
Regulated facilities as part of the groundwater pollution prevention program. Wrote permits, performed compliance and enforcement activities, created outreach materials, conducted educational activities for the public and regulated community, and assisted with regulation and policy changes. Focused on the environmental concerns of small rural towns, communities along the US/Mexico border and low-income rural housing. Supervised two intern positions.

University of Rhode Island Cooperative Extension*:* Program Assistant — Spring-Fall 2000
Assisted on projects aimed at reducing residential non-point pollution and aiding communities with the preservation of drinking water resources. Wrote sections of educational publications, organized community outreach, distributed educational resources.

Woonasquatucket River Greenway Project: Program Coordinator — Spring-Fall 2000
Developed and organized a youth environmental stewardship group with a focus on urban parks and community involvement. Designed and led leadership orientation program, supervised and counseled teen group, and led activities for youth ages 3-17.

Brown University Environmental Science Laboratory: Lab Technician — Fall 1996-Spring 1997/Fall 1998-Fall 1999
Processed soil samples and analyzed data for publication of an ecological nutrient-cycle study. Assisted in the collection of a variety of different field data. Attended lectures, project presentations, and discussions. Conducted background research.

PROFAUNA & FUndación para el DEsarollo de CIencias fisicas y naturales (FUDECI)Venezuela: Intern — Spring 1998
Aided government conservation organization at a wildlife refuge with all specie and area management procedures and studies. Assisted on an expedition into the Amazon investigating indigenous use and basic habitat information of the area's turtle species.

Education and Awards

University of California, Berkeley, Berkeley, California — May 2006
Masters in Public Health - Environmental Health Sciences

Brown University, Providence, Rhode Island — Degree Awarded May 2000
BS in Environmental Science with Honors
Center for Environmental Studies Award for Commitment to Community Service

School for International Training, Mérida, Venezuela — Fall 1997
Venezuela Natural and Cultural Ecology Program

Professional Activities

California Climate Action Team Public Health Workgroup, *California Department of Public Health and California Air Resources Board*

Public Policy Task Force –New Orleans and the Gulf Coast, *Deep South Center for Environmental Justice*

California Environmental Public Health Tracking Program, *California Department of Public Health*

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Publications

Rotkin-Ellman M, Wong K, Solomon G. Seafood Contamination after the BP Gulf Oil Spill and Risks to Vulnerable Populations: A Critique of the FDA Risk Assessment. Environ Health Perspect 120: 157-161. 2012.

Knowlton K**, Rotkin-Ellman M,** Geballe L, Max W, and Solomon G. Six Climate Change-Related Events In The United States Accounted For About $14 Billion In Lost Lives And Health Costs. Health Affairs, 30, no.11 (2011):2167-2176

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Rotkin-Ellman M, Addy K, Gold AJ., and Groffman PM. 2004. Tree Species, Root Decomposition and Subsurface Denitrification Potential in Riparian Wetlands. Plant and Soil. 263:335-344.

Reports

Knowlton, K, Solomon G. and **Rotkin-Ellman M**. Fever Pitch: Mosquito-Borne Dengue Fever Threat Spreading in the Americas. A report produced by the Natural Resources Defense Council. http://www.nrdc.org/health/dengue/files/dengue.pdf

Rotkin-Ellman M and Solomon G. Poisons on Pets II: Toxic Chemicals in Flea and Tick Collars. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/poisonsonpets/files/poisonsonpets.pdf

Rotkin-Ellman M, Quirindongo M, Sass J, Solomon G. Deepest Cuts: Repairing Health Monitoring Programs Slashed Under the Bush Administration. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/health/deepestcuts/deepestcuts.pdf.

Wall M, **Rotkin-Ellman M**, Solomon G. An Uneven Shield: The Record of Enforcement and Violations Under California's Environmental, Health and Workplace Safety Laws. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/legislation/shield/shield.pdf.

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Fields, L., Huang, A., Solomon, GM, **Rotkin-Ellman M**., Simms, P. 2007. Katrina's Wake: Arsenic-Laced Schools and Playgrounds Put New Orleans Children at Risk. A report produced by the Natural Resources Defense Council. http://www.nrdc.org/health/effects/wake/contents.asp

Solomon GM and **Rotkin-Ellman M**. 2006. Contaminants in New Orleans Sediment An Analysis of EPA Data. A report produced by the Natural Resources Defense Council. [http://www.nrdc.org/health/effects/katrinadata/contents.asp]

Rotkin-Ellman M, Kyle AD, Balmes JR. 2005. Assessment of options for tracking of drinking water contaminants and relevant data sources. A working paper produced by the Berkeley Center for Environmental Public Health Tracking, School of Public Health, University of California Berkeley. [http://ehtracking.berkeley.edu/pubs/reports.htm]

Rotkin-Ellman M. and Menetrey K. Large Capacity Septic System Study. 2001. A report produced by the Ground Water Quality Bureau, New Mexico Environment Department. [http://www.nmenv.state.nm.us/gwb/New%20Pages/docs_regs.htm]

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Selected Presentations

Using Environmental Health Data
UCSF Program on Reproductive Health and the Environment - Reach the Decision Makers, (9/10)

The 2006 California Heat Wave: Impacts on Hospitalizations and Emergency Room Visits
Council of State and Territorial Epidemiologists (CSTE) Annual Conference-Environmental Workshop (6/10)
Preparing for Climate Change: Protecting Vulnerable Communities.
California Health Policy Forum. (12/09)

Katrina's Wake: Soil Contamination in New Orleans.
*Race, Place, and the Environment after Katrina, a National Symposium. (*5/08)

Soil Contamination in New Orleans: Impact of the 2005 Hurricanes.
American Public Health Association (APHA) Annual meeting. (11/07)